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Nonfossil Fuel Fired Industrial Boilers– Background Information

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Nonfossil Fuel Fired Industrial Boilers-Background Information

Emission Standards and Engineering Division

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Air, Noise and Radiation
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

March 1982

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1. OVERVIEW

This document was prepared to provide the public and industry with background information on the nonfossil fuel fired boiler source category in support of potential new source performance standards. Nonfossil fuels discussed and analyzed include wood, solid waste, bagasse, and nonfossil/fossil mixtures. Background information for fossil fuel fired boilers (coal, oil, and natural gas) is included in a separate two volume document, EPA-450/3-82-006a and b.

This document contains information on the use of nonfossil fuel fired boilers in different industries and an assessment of controlled and uncontrolled emissions from different configurations of boilers firing nonfossil fuels. Cost and environmental assessments for several model boiler configurations to meet alternative control levels are also presented.

2.0 INTRODUCTION

2.1 BACKGROUND AND AUTHORITY FOR STANDARDS

Before standards of performance are proposed as a Federal regulation, air pollution control methods available to the affected industry and the associated costs of installing and maintaining the control equipment are examined in detail. Various levels of control based on different technologies and degrees of efficiency are expressed as control alternatives. Each of these alternatives is studied by EPA as a prospective basis for a standard. The alternatives are investigated in terms of their impacts on the economics and well-being of the industry, the impacts on the national economy, and the impacts on the environment. This document summarizes the information obtained through these studies so that interested persons will be able to see the information considered by EPA in the development of the proposed standard.

Standards of performance for new stationary sources are established under Section 111 of the Clean Air Act (42 U.S.C. 7411) as amended, hereinafter referred to as the Act. Section 111 directs the Administrator to establish standards of performance for any category of new stationary source of air pollution which ". . . causes, or contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare."

The Act requires that standards of performance for stationary sources reflect ". . . the degree of emission reduction achievable which (taking into consideration the cost of achieving such emission reduction, and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated for that category of sources." The standards apply only to stationary sources, the construction or modification of which commences after regulations are proposed by publication in the Federal Register.

The 1977 amendments to the Act altered or added numerous provisions that apply to the process of establishing standards of performance.

1. EPA is required to list the categories of major stationary sources that have not already been listed and regulated under standards of performance. Regulations must be promulgated for these new categories on the following schedule:

a. 25 percent of the listed categories by August 7, 1980.

b. 75 percent of the listed categories by August 7, 1981.

c. 100 percent of the listed categories by August 7, 1982.

A governor of a State may apply to the Administrator to add a category not on the list or may apply to the Administrator to have a standard of performance revised.

2. EPA is required to review the standards of performance every 4 years and, if appropriate, revise them.

3. EPA is authorized to promulgate a standard based on design, equipment, work practice, or operational procedures when a standard based on emission levels is not feasible.

4. The term "standards of performance" is redefined, and a new term "technological system of continuous emission reduction" is defined. The new definitions clarify that the control system must be continuous and may include a low- or non-polluting process or operation.

5. The time between the proposal and promulgation of a standard under Section 111 of the Act may be extended to 6 months.

Standards of performance, by themselves, do not guarantee protection of health or welfare because they are not designed to achieve any specific air quality levels. Rather, they are designed to reflect the degree of emission limitation achievable through application of the best adequately demonstrated technological system of continuous emission reduction, taking into consideration the cost of achieving such emission reduction, any non-air-quality health and environmental impacts, and energy requirements.

Congress had several reasons for including these requirements. First, standards with a degree of uniformity are needed to avoid situations where some States may attract industries by relaxing standards relative to other

States. Second, stringent standards enhance the potential for long-term growth. Third, stringent standards may help achieve long-term cost savings by avoiding the need for more expensive retrofitting when pollution ceilings may be reduced in the future. Fourth, certain types of standards for coal-burning sources can adversely affect the coal market by driving up the price of low-sulfur coal or effectively excluding certain coals from the reserve base because their untreated pollution potentials are high. Congress does not intend that new source performance standards contribute to these problems.

Promulgation of standards of performance does not prevent State or local agencies from adopting more stringent emission limitations for the same sources. States and local agencies if authorized by State law are free under Section 116 of the Act to establish even more stringent emission limits than those established under Section 111 or those necessary to attain or maintain the National Ambient Air Quality Standards (NAAQS) under Section 110. Thus, new sources may in some cases be subject to limitations more stringent than standards of performance under section 111, and prospective owners and operators of new sources should be aware of this possibility in planning for such facilities.

A similar situation may arise when a major emitting facility is to be constructed in a geographic area that falls under the prevention of significant deterioration of air quality provisions of Part C of the Act. These provisions require, among other things, that major emitting facilities to be constructed in such areas are to be subject to best available control technology. The term Best Available Control Technology (BACT), as defined in the Act, means

> . . . an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this Act emitted from, or which results from, any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is

achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of each such pollutant. In no event shall application of "best available control technology" result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to Sections 111 or 112 of this Act. (Section 169(3))."

Although standards of performance are normally structured in terms of numerical emission limits where feasible, alternative approaches are sometimes necessary. In some cases physical measurement of emissions from a new source may be impractical or exorbitantly expensive. Section 111(h) provides that the Administrator may promulgate a design or equipment standard in those cases where it is not feasible to prescribe or enforce a standard of performance. For example, emissions of hydrocarbons from storage vessels for petroleum liquids are greatest during tank filling. The nature of the emissions, high concentrations for short periods during filling and low concentrations for longer periods during storage, and the configuration of storage tanks make direct emission measurement impractical. Therefore, a more practical approach to standards of performance for storage vessels has been equipment specification.

In addition, Section 111(i) authorizes the Administrator to grant waivers of compliance to permit a source to use innovative continuous emission control technology. In order to grant the waiver, the Administrator must find: (1) a substantial likelihood that the technology will produce greater emission reductions than the standards require or an equivalent reduction at lower economic energy or environmental cost; (2) the proposed system has not been adequately demonstrated; (3) the technology will not cause or contribute to an unreasonable risk to the public health, welfare, or safety; (4) the governor of the State where the source is located consents; and (5) the waiver will not prevent the attainment or maintenance of any ambient standard. A waiver may have conditions attached to assure the source will not prevent attainment of any NAAQS. Any such condition will have the force of a performance standard. Finally, waivers have definite end dates and may be terminated earlier if the conditions are not met or if the system fails to perform as expected. In such a case, the source may be given up to 3 years to meet the standards with a mandatory progress schedule.

2.2 SELECTION OF CATEGORIES OF STATIONARY SOURCES

Section 111 of the Act directs the Administrator to list categories of stationary sources. The Administrator ". . . shall include a category of sources in such list if in his judgment it causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare." Proposal and promulgation of standards of performance are to follow.

Since passage of the Clean Air Amendments of 1970, considerable attention has been given to the development of a system for assigning priorities to various source categories. The approach specifies areas of interest by considering the broad strategy of the Agency for implementing the Clean Air Act. Often, these "areas" are actually pollutants emitted by stationary sources. Source categories that emit these pollutants are evaluated and ranked by a process involving such factors as (1) the level of emission control (if any) already required by State regulations, (2) estimated levels of control that might be required from standards of performance for the source category, (3) projections of growth and replacement of existing facilities for the source category, and (4) the estimated incremental amount of air pollution that could be prevented in a preselected future year by standards of performance for the source category. Sources for which new source performance standards were promulgated or under development during 1977, or earlier, were selected on these criteria.

The Act amendments of August 1977 establish specific criteria to be used in determining priorities for all major source categories not yet listed by EPA. These are (1) the quantity of air pollutant emissions that each such category will emit, or will be designed to emit; (2) the extent to which each such pollutant may reasonably be anticipated to endanger public health or welfare; and (3) the mobility and competitive nature of each such category of sources and the consequent need for nationally applicable new source standards of performance.

The Administrator is to promulgate standards for these categories according to the schedule referred to earlier.

In some cases it may not be feasible immediately to develop a standard for a source category with a high priority. This might happen when a program of research is needed to develop control techniques or because techniques for sampling and measuring emissions may require refinement. In the developing of standards, differences in the time required to complete the necessary investigation for different source categories must also be considered. For example, substantially more time may be necessary if numerous pollutants must be investigated from a single source category. Further, even late in the development process the schedule for completion of a standard may change. For example, inability to obtain emission data from well-controlled sources in time to pursue the development process in a systematic fashion may force a change in scheduling. Nevertheless, priority ranking is, and will continue to be, used to establish the order in which projects are initiated and resources assigned.

After the source category has been chosen, the types of facilities within the source category to which the standard will apply must be determined. A source category may have several facilities that cause air pollution, and emissions from some of these facilities may vary from insignificant to very expensive to control. Economic studies of the source category and of applicable control technology may show that air pollution control is better served by applying standards to the more severe pollution sources. For this reason, and because there is no adequately demonstrated system for controlling emissions from certain facilities, standards often do not apply to all facilities at a source. For the same reasons, the standards may not apply to all air pollutants emitted. Thus, although a source category may be selected to be covered by a standard of performance, not all pollutants or facilities within that source category may be covered by the standards.

2.3 PROCEDURE FOR DEVELOPMENT OF STANDARDS OF PERFORMANCE

Standards of performance must (1) realistically reflect best demonstrated control practice; (2) adequately consider the cost, the non-air-quality health and environmental impacts, and the energy requirements of such control; (3) be applicable to existing sources that are modified or reconstructed as well as new installations; and (4) meet these conditions for all variations of operating conditions being considered anywhere in the country.

The objective of a program for developing standards is to identify the best technological system of continuous emission reduction that has been adequately demonstrated. The standard-setting process involves three principal phases of activity: (1) information gathering, (2) analysis of the information, and (3) development of the standard of performance.

During the information-gathering phase, industries are queried through a telephone survey, letters of inquiry, and plant visits by EPA representatives. Information is also gathered from many other sources, and a literature search is conducted. From the knowledge acquired about the industry, EPA selects certain plants at which emission tests are conducted to provide reliable data that characterize the pollutant emissions from well-controlled existing facilities.

In the second phase of a project, the information about the industry and the pollutants emitted is used in analytical studies. Hypothetical "model plants" are defined to provide a common basis for analysis. The model plant definitions, national pollutant emission data, and existing State regulations governing emissions from the source category are then used in establishing "control alternatives." These control alternatives are essentially different levels of emission control.

EPA conducts studies to determine the impact of each control alternative on the economics of the industry and on the national economy, on the environment, and on energy consumption. From several possibly applicable alternatives, EPA selects the single most plausible control alternative as the basis for a standard of performance for the source category under study.

In the third phase of a project, the selected control alternative is translated into a standard of performance, which, in turn, is written in the form of a Federal regulation. The Federal regulation, when applied to newly constructed plants, will limit emissions to the levels indicated in the selected control alternative.

As early as is practical in each standard-setting project, EPA representatives discuss the possibilities of a standard and the form it might take with members of the National Air Pollution Control Techniques Advisory Committee. Industry representatives and other interested parties also participate in these meetings.

The information acquired in the project is summarized in the background information document (BID). The BID, the standard, and a preamble explaining the standard are widely circulated to the industry being considered for control, environmental groups, other government agencies, and offices within EPA. Through this extensive review process, the points of view of expert reviewers are taken into consideration as changes are made to the documentation.

A "proposal package" is assembled and sent through the offices of EPA Assistant Administrators for concurrence before the proposed standard is officially endorsed by the EPA Administrator. After being approved by the EPA Administrator, the preamble and the proposed regulation are published in the Federal Register.

As a part of the Federal Register announcement of the proposed regulation, the public is invited to participate in the standard-setting process. EPA invites written comments on the proposal and also holds a public hearing to discuss the proposed standard with interested parties. All public comments are summarized and incorporated into a second volume of the BID. All information reviewed and generated in studies in support of the standard of performance is available to the public in a "docket" on file in Washington, D. C.

Comments from the public are evaluated, and the standard of performance may be altered in response to the comments.

The significant comments and EPA's position on the issues raised are included in the "preamble" of a promulgation package," which also contains the draft of the final regulation. The regulation is then subjected to another round of review and refinement until it is approved by the EPA Administrator. After the Administrator signs the regulation, it is published as a "final rule" in the Federal Register.

2.4 CONSIDERATION OF COSTS

Section 317 of the Act requires an economic impact assessment with respect to any standard of performance established under Section 111 of the Act. The assessment is required to contain an analysis of: (1) the costs of compliance with the regulation, including the extent to which the cost of compliance varies depending on the effective date of the regulation and the development of less expensive or more efficient methods of compliance; (2) the potential inflationary or recessionary effects of the regulation; (3) the effects the regulation might have on small business with respect to competition; (4) the effects of the regulation on consumer costs; and (5) the effects of the regulation on energy use. Section 317 also requires that the economic impact assessment be as extensive as practicable.

The economic impact of a proposed standard upon an industry is usually addressed both in absolute terms and in terms of the control costs that would be incurred as a result of compliance with typical, existing State control regulations. An incremental approach is necessary because both new and existing plants would be required to comply with State regulations in the absence of a Federal standard of performance. This approach requires a detailed analysis of the economic impact from the cost differential that would exist between a proposed standard of performance and the typical State standard.

Air pollutant emissions may result in additional costs for water treatment and captured potential air pollutants may pose a solid waste disposal problem. The total environmental impact of an emission source must, therefore, be analyzed and the costs determined whenever possible.

A thorough study of the profitability and price-setting mechanisms of the industry is essential to the analysis so that an accurate estimate of potential adverse economic impacts can be made for proposed standards. It is also essential to know the capital requirements for pollution control systems already placed on plants so that the additional capital requirements necessitated by these Federal standards can be placed in proper perspective. Finally, it is necessary to assess the availability of capital to provide the additional control equipment needed to meet the standards of performance.

2.5 CONSIDERATION OF ENVIRONMENTAL IMPACTS

Section 102(2)(C) of the National Environmental Policy Act (NEPA) of 1969 requires Federal agencies to prepare detailed environmental impact statements on proposals for legislation and other major Federal actions significantly affecting the quality of the human environment. The objective of NEPA is to build into the decisionmaking process of Federal agencies a careful consideration of all environmental aspects of proposed actions.

In a number of legal challenges to standards of performance for various industries, the United States Court of Appeals for the District of Columbia Circuit has held that environmental impact statements need not be prepared by the Agency for proposed actions under Section 111 of the Clean Air Act. Essentially, the Court of Appeals has determined that the best system of emission reduction requires the Administrator to take into account counter-productive environmental effects of a proposed standard, as well as economic costs to the industry. On this basis, therefore, the Court established a narrow exemption from NEPA for EPA determination under Section 111.

In addition to these judicial determinations, the Energy Supply and Environmental Coordination Act (ESECA) of 1974 (PL-93-319) specifically exempted proposed actions under the Clean Air Act from NEPA requirements. According to Section 7(c)(1), "No action taken under the Clean Air Act shall be deemed a major Federal action significantly affecting the quality of the human environment within the meaning of the National Environmental Policy Act of 1969." (15 U.S.C. 793(c)(1)).

Nevertheless, the Agency has concluded that the preparation of environmental impact statements could have beneficial effects on certain regulatory actions. Consequently, although not legally required to do so by section 102(2)(C) of NEPA, EPA has adopted a policy requiring that environmental impact statements be prepared for various regulatory actions, including standards of performance developed under Section 111 of the Act. This voluntary preparation of environmental impact statements, however, in no way legally subjects the Agency to NEPA requirements.

To implement this policy, a separate section in this document is devoted solely to an analysis of the potential environmental impacts associated with the proposed standards. Both adverse and beneficial impacts in such areas as air and water pollution, increased solid waste disposal, and increased energy consumption are discussed.

2.6 IMPACT ON EXISTING SOURCES

Section 111 of the Act defines a new source as ". . . any stationary source, the construction or modification of which is commenced . . ." after the proposed standards are published. An existing source is redefined as a new source if "modified" or "reconstructed" as defined in amendments to the general provisions of Subpart A of 40 CFR Part 60, which were promulgated in the Federal Register on December 16, 1975 (40 FR 58416).

Promulgation of a standard of performance requires States to establish standards of performance for existing sources in the same industry under Section 111 (d) of the Act if the standard for new sources limits emissions of a designated pollutant (i.e., a pollutant for which air quality criteria have not been issued under Section 108 or which has not been listed as a hazardous pollutant under Section 112). If a State does not act, EPA must establish such standards. General provisions outlining procedures for control of existing sources under Section 111(d) were promulgated on November 17, 1975, as Subpart B of 40 CFR Part 60 (40 FR 53340).

2.7 REVISION OF STANDARDS OF PERFORMANCE

Congress was aware that the level of air pollution control achievable by any industry may improve with technological advances. Accordingly, Section 111 of the Act provides that the Administrator ". . . shall, at least every 4 years, review and, if appropriate, revise . . ." the standards. Revisions are made to assure that the standards continue to reflect the best systems that become available in the future. Such revisions will not be retroactive, but will apply to stationary sources constructed or modified after the proposal of the revised standards.

3. NONFOSSIL FUEL FIRED BOILER CHARACTERIZATION

This chapter describes the nonfossil fuel fired boiler (NFFB) source category and its processes. Typical NFFB facilities and their emissions are discussed as a reference for evaluating potential impacts from alternative control levels.

The chapter is divided into three sections. Section 3.1 presents a brief overview of the source category, Section 3.2 describes the operating and emission characteristics of the various types of NFFBs, and Section 3.3 presents the existing State and Federal emissions regulations for NFFBs.

3.1 GENERAL DESCRIPTION

This section defines the source category and gives a brief description of the types of fuel burned. A profile of present boiler usage is presented along with projected future growth. Detailed growth projections are presented in Chapter 9.

3.1.1 Definition of Source Category

The following definition of the NFFB source category provides a basis for subsequent discussion in this document, but does not constitute a legal definition. The legal definition of the source category will be contained in the regulation written from this document.

The NFFB source category includes any furnace or boiler used in the production of steam or hot water from the combustion of any of the following:

- Wood
- Bagasse (Sugar Cane Residue)
- General Solid Waste (GSW)
    1) Municipal Solid Waste (MSW)
    2) Industrial Solid Waste (ISW)
    3) Refuse Derived Fuel (RDF).

3.1.2 Types of Fuels Burned

Categories of nonfossil materials burned in boilers include: wood, bagasse, and general solid waste (GSW). These categories group together nonfossil fuels of similar origin and type. In addition, although NFFBs are found throughout many industrial classifications, certain industrial classes are the principal users of boilers firing each of these types of fuels. These three categories of nonfossil fuels and their principal users are discussed below.

3.1.2.1 Wood. Wood is typically used to fire boilers in the paper and allied products industry, the forest products industry, and the furniture industry.[1] Within these industries, the types of wood burned range from sawdust and sanderdust to wood slats, wood chips, and wood bark. Other sources of wood for fuel include: discarded packing crates, wood pallets, and wood waste from construction/demolition activities. The types of wood burned as fuel within each industrial category are typically wastes resulting from processes in that industry.

3.1.2.2 Bagasse. Bagasse is an agricultural waste which is frequently burned as a fuel. Bagasse consists of the fibrous residue left after processing sugar cane. This fuel is available seasonally. and its use has been limited to the sugar cane industry, which is located in Florida, Louisiana, Texas, Hawaii, and Puerto Rico.[2]

3.1.2.3 General Solid Waste. GSW consists of refuse and garbage from cities, communities, and industries. It includes waste from residences, commercial establishments, and industries that has been collected and transferred to a central point before combustion. Because of their similarities, MSW, ISW, and RDF are included in GSW. Boilers firing GSW are found in manufacturing plants, district heating plants, municipal heating plants, and electric utilities.

Wood, paper, metal, glass, and garbage typically constitute MSW. However, the exact constituents of MSW may vary both seasonally and geographically. For example, during the fall, the organic content of MSW is greater than at other times of the year because it contains an increased amount of leaves and tree clippings. Components may also vary geographically, depending upon the nature of the industries contributing solid waste and the relative volume of the industries' waste compared to that contributed by the domestic population. The heating value of the MSW is expected to increase, primarily due to an increase in the use of plastics.[3]

Industrial solid waste includes processing wastes and plant trash. It is composed of paper, cardboard, plastic, rubber, textiles, wood, and refuse.[4] The exact composition for any one site is usually relatively constant because the industrial activities and processes that generate the waste are usually well regulated.[5] However the composition from different sites may vary.

Refuse derived fuel is GSW that is processed or classified before combustion. Whereas MSW and ISW are burned in the same form as they are received at the boiler site, GSW is processed and the noncombustibles, such as glass and metal, are removed to produce RDF. RDF can be burned alone, or burned as a coal supplement in fossil fuel-fired steam generators.[6] Both approaches are being implemented.

3.1.3 Boiler Usage Profile

This section presents population data for boilers burning nonfossil fuels. The size ranges for these boilers and projected population are also presented. Figure 3-1 graphically presents the installed capacities for each NFFB fuel category in 1978. This figure shows that wood is the most common fuel for NFFBs, followed by bagasse and GSW. However, based on growth projections discussed in the following sections, GSW-fired boilers will become much more common in the future.

3.1.3.1 Wood-Fired Boilers. There are approximately 1600 wood-fired boilers in operation in the United States with a total capacity of 30.5 GW (1.04×10^{11} Btu/hr) thermal input.[9] These range in size from 0.44 MW (1.5×10^6 Btu/hr) to 420 MW (1.43×10^9 Btu/hr) thermal input.[10] Figure 3-2 shows the size distribution of watertube wood-fired boilers sold for 1970 through 1978 based on American Boiler Manufacturers Association (ABMA) data. The largest numbers of wood-fired boilers are in the states with the most forest related industries - Oregon, Washington, Georgia,

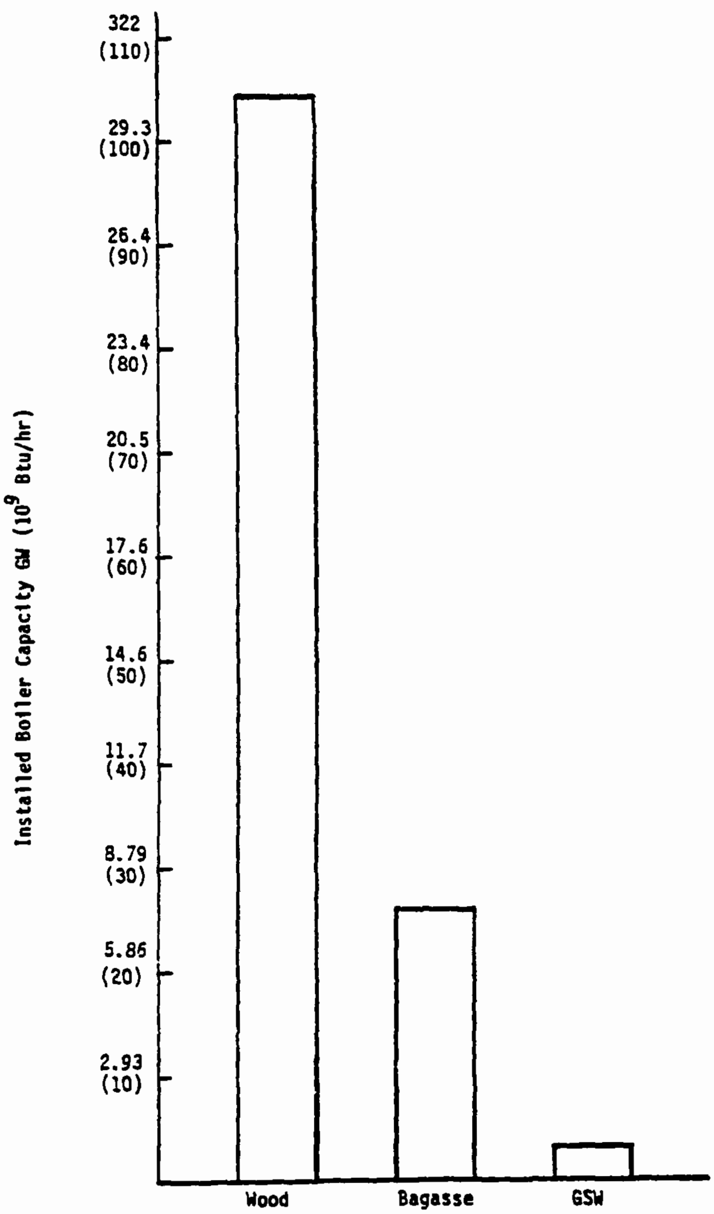

Figure 3-1. Existing Nonfossil Fuel Fired Boiler Capacities in 1978.[a,b]

a. References 7,8.
b. This figure includes only boilers firing nonfossil fuel as the primary fuel. However, some of the boilers shown may also fire some fossil fuel either separately, or in conjunction with nonfossil fuel.

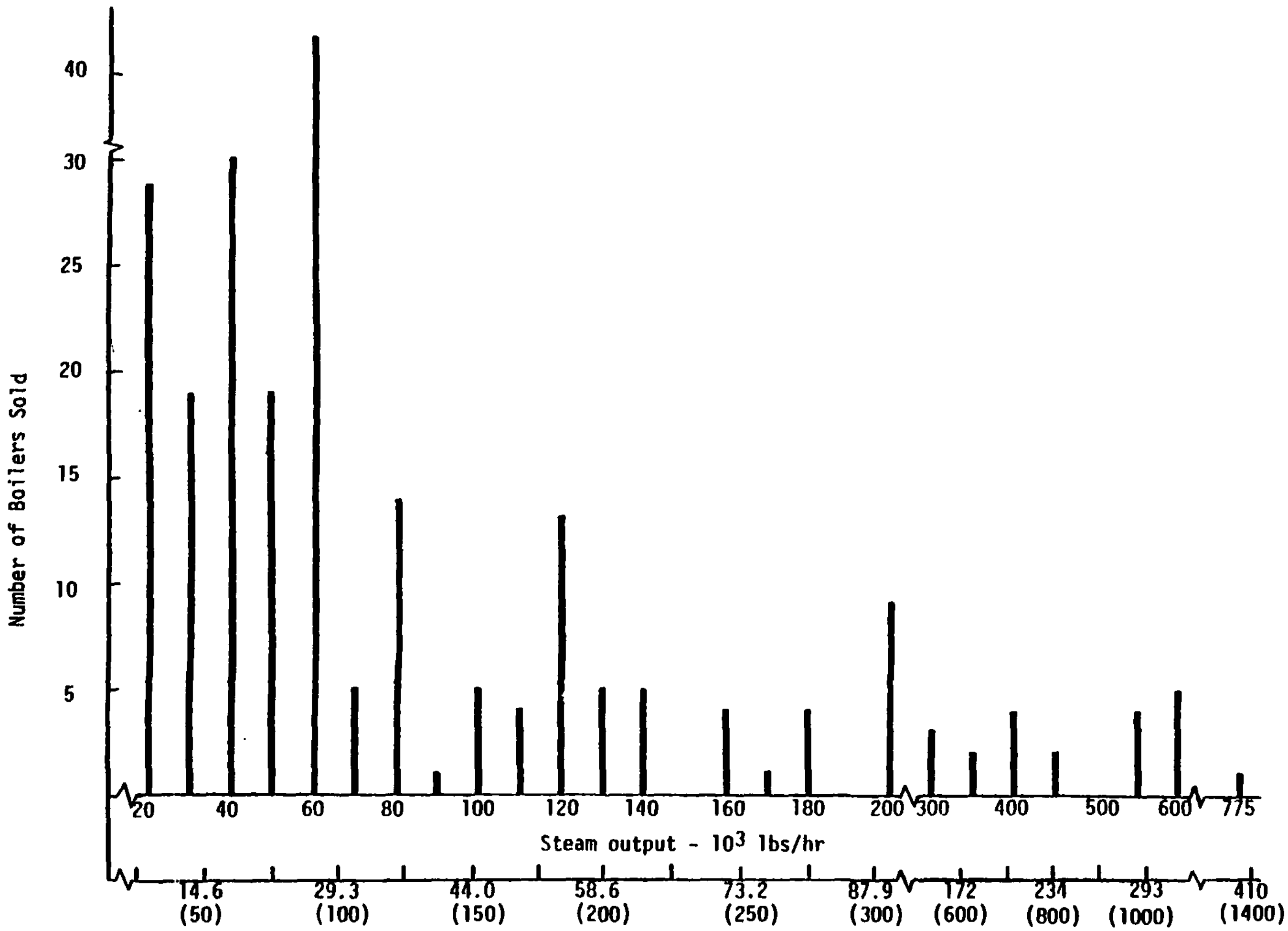

Figure 3-2. Size Distribution of Wood-Fired Watertube Boilers Sold From 1970 through 1978.[a,b]

a. Reference 11.

b. These data include only boilers firing wood as the primary fuel. However, many of the boilers, especially in the larger size ranges, may cofire wood and an auxiliary fossil fuel.

Florida and Arkansas.[12] As shown in Table 3-1, a total of 1950 MW (6.65×10^9 Btu/hr) of new wood-fired boiler capacity will be installed per year in 1982 through 1990. This is due to growth of the major industries using wood-fired boilers, the trends in these industries to replace fossil fuels with wood, and replacement of older existing boilers with new ones.

3.1.3.2 Bagasse-Fired Boilers. Approximately 185 boilers that burn bagasse are currently in operation in Florida, Louisiana, Texas, Hawaii, and Puerto Rico.[14] Bagasse boilers range in capacity from 3.8 MW (13×10^6 Btu/hr) to 236 MW (805×10^6 Btu/hr) thermal input.[15] Figure 3-3 shows the size distribution of watertube bagasse-fired boilers sold for 1970 through 1978. As shown in Table 3-1, new bagasse-fired boiler capacity is expected to be installed at an average rate of 390 MW (1.36×10^9 Btu/hr) per year for 1982 through 1990. This growth is due to an actual growth in boiler capacity expected in Florida, and to the replacement of older boilers with new ones in other areas.

Other agricultural wastes, such as peanut hulls, cotton gin trash, peach pits, corn husks, walnut shells, and olive pits may be burned as a boiler fuel. However, there are only five boilers that have been found presently burning these types of wastes. Most agricultural wastes are more valuable as a chemical or animal feedstock than as boiler fuel.[17]

3.1.3.3 General Solid Waste-Fired Boilers. This section includes boilers firing municipal and industrial solid wastes, and refuse derived fuels.

3.1.3.3.1 Municipal Solid Waste-Fired Boilers. Municipal solid waste is presently burned in boilers ranging in capacity from 1.3 MW (4.5×10^6 Btu/hr) to 85 MW (290×10^6 Btu/hr) thermal input.[18,19] Two boilers representing the most recent advances in large mass burning technology have 85 MW (290×10^6 Btu/hr) thermal input capacity each. A boiler as large as these typical new units is capable of burning approximately 22,700 kg (50,000 lb) of refuse per hour. Approximately 15 large MSW boilers are currently in operation or under construction in the United States.[20] The larger boilers are located near urban population centers.

TABLE 3-1. NONFOSSIL FUEL-FIRED BOILER POPULATION DATA[13]

Fuel	Estimated 1978 population		Estimated Boiler Sales Per Year (1982 - 1990)	
	Total Capacity GW (10^6 Btu/hr)	Number of Boilers	Total Capacity MW (10^6 Btu/hr)	Number of Boilers
Wood	30.7 (104,750)	1600	1950 (6650)	37.0
Bagasse	7.7 (26,300)	185	390 (1360)	4.4
MSW[a]	0.68 (2,325)	20	360 (1240)	5.6
MSW,ISW[b]	0.21 (714)	57	170 (594)	42
RDF[d]	0.17 (567)	5[c]	380 (1310)	6.4[d]

[a]Does not include small modular incinerators with heat recovery.

[b]Includes only small modular incinerators with heat recovery. Small modular incinerators generally range from 1.3 to 17.6 MW (4.5×10^6 to 60×10^6 Btu/hr) of heat input capacity.

[c]Estimated assuming one RDF-fired boiler per RDF production facility.

[d]Based on 100 percent RDF firing.

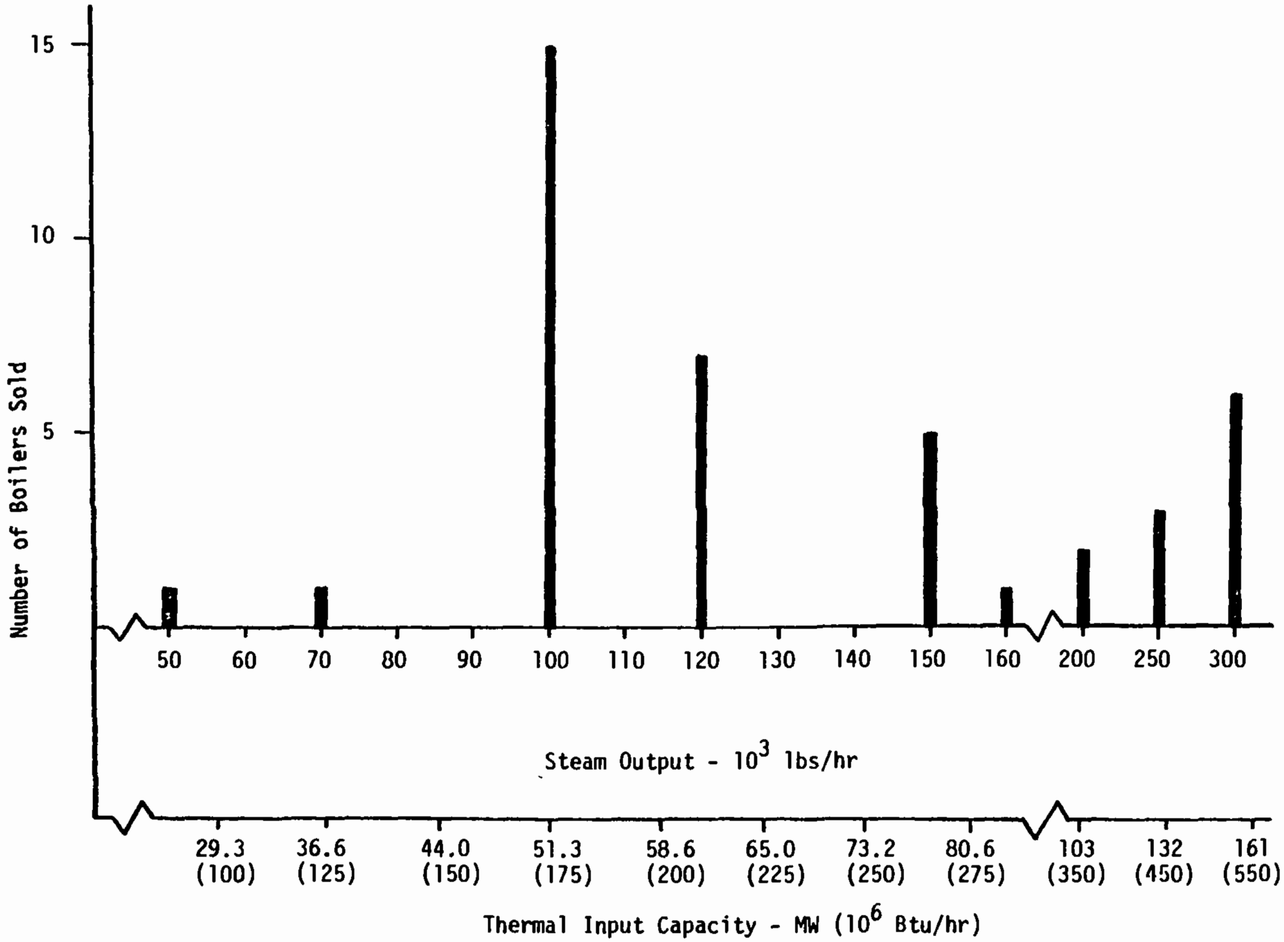

Figure 3-3. Size Distribution of Bagasse-Fired Watertube Boilers Sold From 1970 through 1978.[16]

Approximately six small shop-assembled (modular) MSW boilers are currently being used by small cities and towns.[21] Small modular boilers firing MSW range in unit size from 1.3 MW (4.5 x 10^6 Btu/hr) to 11.1 MW (38 x 10^6 Btu/hr).[22,23] Municipalities typically use facilities consisting of several units, and add additional units as required. The number of boilers burning MSW is expected to increase in the future as municipalities look for alternatives to landfilling, and utilities, industries, and municipalities seek cheaper sources of fuels. As shown in Table 3-1, projected sales of MSW-fired boilers will be 360 MW (1.24 x 10^9 Btu/hr) of heat input capacity per year in 1982 through 1990 (excluding small modular units). The small modular boilers have projected sales of 170 MW (5.94 x 10^8 Btu/hr) of heat input capacity per year in 1982 through 1990 including boilers firing MSW and ISW.

3.1.3.3.2 Industrial Solid Waste-Fired Boilers. ISW is primarily burned in the same type of small modular boilers used to burn MSW. At present there are approximately 50 of these units installed at industrial facilities.[24] Small modular boilers firing ISW can range in size up to 17.6 MW (60 x 10^6 Btu/hr).[23] ISW can also be fired in the large mass burn boilers which fire MSW. There is also one industrial facility which adds its refuse to coal and burns the mixture in a conventional coal-fired boiler.

3.1.3.3.3 Refuse Derived Fuel-Fired Boilers. RDF, when properly processed, can be fired in any boiler designed to burn coal. This includes stoker and pulverized coal units.[25] There are also six facilities either operational or under construction where RDF will be fired alone in boilers specifically designed for this fuel. Two of these boilers have capacities of 97 MW (330 x10^6 Btu/hr) and 126 MW (430 x 10^6 Btu/hr). There are about 21 RDF production facilities in operation or under construction.[26] However, some of the RDF presently produced is not burned as a fuel, but is landfilled because of a lack of sales. As shown in Table 3-1, new RDF-fired boiler capacity is expected to be installed at an average rate of 380 MW (1.31 x 10^9 Btu/hr) per year from 1982 through 1990.

3.2 FACILITIES AND THEIR EMISSIONS

This section discusses the common boiler types used for each fuel category and their effect on uncontrolled emissions. Other operational factors which affect uncontrolled emissions are also presented.

As shown in the following discussion, particulate matter (PM) emissions are the primary pollutant emitted by NFFBs. Because of this, the discussion of uncontrolled emissions will primarily focus on PM emissions. Sulfur dioxide emissions from NFFBs are low due to the low fuel sulfur contents. Little information is available on nitrogen oxide emissions or factors affecting emissions of nitrogen oxides.

3.2.1 Wood-Fired Boilers.

Table 3-2 presents the distribution of firing methods by size category for wood-fired boilers sold between 1970 and 1978.

3.2.1.1 Facility Description. As shown in Table 3-2, the most common firing method for wood-fired boilers larger than 45,400 kg/hr (100,000 lb/hr) steam is the spreader stoker. With this boiler wood enters the furnace through a fuel chute and is spread pneumatically or mechanically across the furnace, where part of the fuel burns while in suspension. Simultaneously, large pieces of fuel are spread in a thin, even bed on a stationary or moving grate. The flame over the grate radiates heat back to the fuel to aid combustion. The combustion area of the furnace is lined with heat exchange tubes (waterwalls). A representative new wood-fired spreader stoker with a heat input capacity of 44 MW (150 x 10^6 Btu/hr) is shown in Figure 3-4.

Figure 3-4 also shows material balances for this boiler. Wood fuel entering the boiler commonly contains about 50 percent moisture (wet basis) by weight. An ultimate analysis for wood is shown in Table 3-3 along with some representative analysis of other fuels often fired in wood-fired and wood/coal cofired boilers. The heating value of the wood is 10,600 kJ/kg (4560 Btu/lb) as fired. This low heating value results from the high moisture content of the fuel.

For a wood with this ultimate analysis, approximately 14,900 kg/hr (32,900 lb/hr) of wood fuel is required to provide the 44 MW

TABLE 3-2. WOOD-FIRED BOILERS SOLD BETWEEN 1970 AND 1978 BY FIRING METHOD AND SIZE CATEGORY[27]

Firing Methods[a]	Steam Capacity - 10^3 kg/hr (10^3 lbs/hr) 7.3 - 45 (10 - 100)	46 - 113 (101 - 250)	114 - 227 (251 - 500)	Over 227 (Over 500)	Percent of total sales
Spreader Stoker - percent of size range[b]	20.6	67.8	100.0	100.0	65.9
Overfeed Stoker - percent of size range[b]	41.2	32.2	0	0	21.9
Underfeed Stoker - percent of size range[b]	1.9	0	0	0	0.6
Other[c] - percent of size range[b]	31.7	0	0	0	10.1
Suspension[d] - percent of size range[b]	4.6	0	0	0	1.5

[a]This table includes only boilers firing wood as the primary fuel. The firing method is for the wood fuel only. Many of the boilers, especially in the larger size ranges, cofire wood and an auxiliary fossil fuel.

[b]Value is percent of total capacity sold in that size range.

[c]Includes fuel cells and fluidized bed combustion.

[d]Suspension boilers are defined as those which burn only small sized fuel (such as sanderdust) and the fuel is burned 100 percent in suspension.

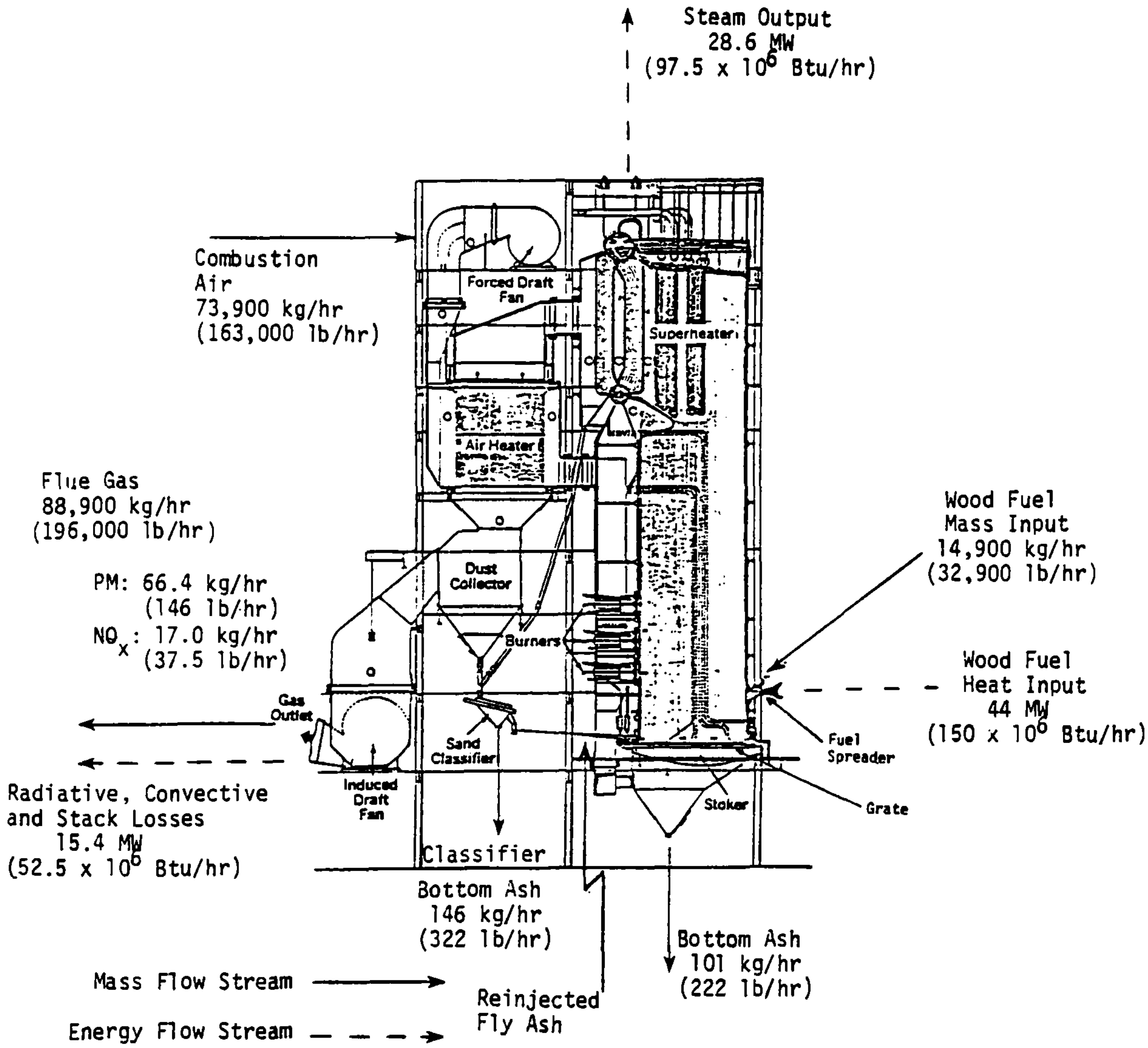

Figure 3-4. Energy and material balances for a representative wood-fired spreader stoker boiler.[28]

<u>Steam: Its Generation and Use</u>, 39th ed., <u>The Babcock & Wilcox Company</u> (New York, 1978) p. 11-4.

TABLE 3-3. REPRESENTATIVE ULTIMATE ANALYSES OF FUELS FIRED IN WOOD-FIRED AND WOOD/COAL COFIRED BOILERS[29,30]

Fuel[a]	Composition, percent by weight (wet basis)							Gross Heating Value kJ/kg (Btu/lb)
	Moisture	Carbon	Hydrogen	Nitrogen	Oxygen	Sulfur	Ash	
Wood	50.00	26.95	2.85	0.08	19.10	0.02	1.00	10,600 (4,560)
HAB	50.00	25.85	2.73	0.08	18.32	0.02	3.00	10,160 (4,370)
SLW	50.00	26.68	2.83	0.08	18.91	0.02	1.49[b]	10,500 (4,513)
HSE	8.79	64.80	4.43	1.30	6.56	3.54	10.58	27,440 (11,800)
LSW	20.80	57.60	3.20	1.20	11.20	0.60	5.40	22,330 (9,600)

[a]Wood - Hog Fuel (wood/bark mixture)
HAB - High Ash Bark
SLW - Salt-Laden Wood
HSE - High Sulfur Eastern Coal
LSW - Low Sulfur Western Coal

[b]Includes salt which makes up 0.5 percent of the fuel on a wet basis.

(150×10^6 Btu/hr) thermal input for the boiler shown in Figure 3-4. In addition to wood waste, 50 percent excess air is injected into the boiler to sustain combustion of the wood fuel. A portion of the combustion air is injected through the grate to drive off the volatiles and burn the char, while the remainder is fed into the boiler above the grate to complete combustion. The relative amounts of underfire and overfire air vary considerably in actual practice.[31]

Wood waste combustion causes ash accumulation in the boiler ash pit and discharge of particulate matter (PM) with flue gas from the stack. Figure 3-4 shows ash accumulation and flue gas discharge rates for a typical wood-fired boiler. The flue gas leaves the boiler containing PM (fly ash) and nitrogen oxides (NO_x) as shown in Figure 3-4. Small amounts of SO_2 may also be present. However, available test data have shown SO_2 emissions to be below 8.6 ng/J (0.02 lb/10^6 Btu) and in many cases below the detection limit for the applicable EPA test method.[33] A particle size distribution of uncontrolled wood PM emissions is shown in Figure 3-5.

In addition, Polycyclic Organic Matter (POM) has also been identified as a pollutant from wood combustion. Although these emissions are not specifically addressed in this study, some emission data were gathered and are presented below.

One EPA test measured one type of POM, Benzo-a-Pyrene (BaP), at the inlet and outlet of a wet scrubber particulate control device located on a 49,900 kg steam/hr (110,000 lb steam/hr) wood-fired boiler. The BaP emissions averaged 3.16×10^{-8} lbs/10^6 Btu at the inlet and 6.94×10^{-8} lbs/10^6 Btu at the outlet.[33] The apparent increase in BaP emissions through the control device is unexplained but because of the low values reported is possibly due to sampling and analytical error. Three other wood-fired boilers were also tested for BaP emissions. They were tested at the outlet of the mechanical collectors used as the first particulate control device on these boilers. The emissions averaged less than 2.9×10^{-5} lbs/10^6 Btu for all three boilers.[33] These tests indicate emission values of BaP for wood-fired boilers are very low.

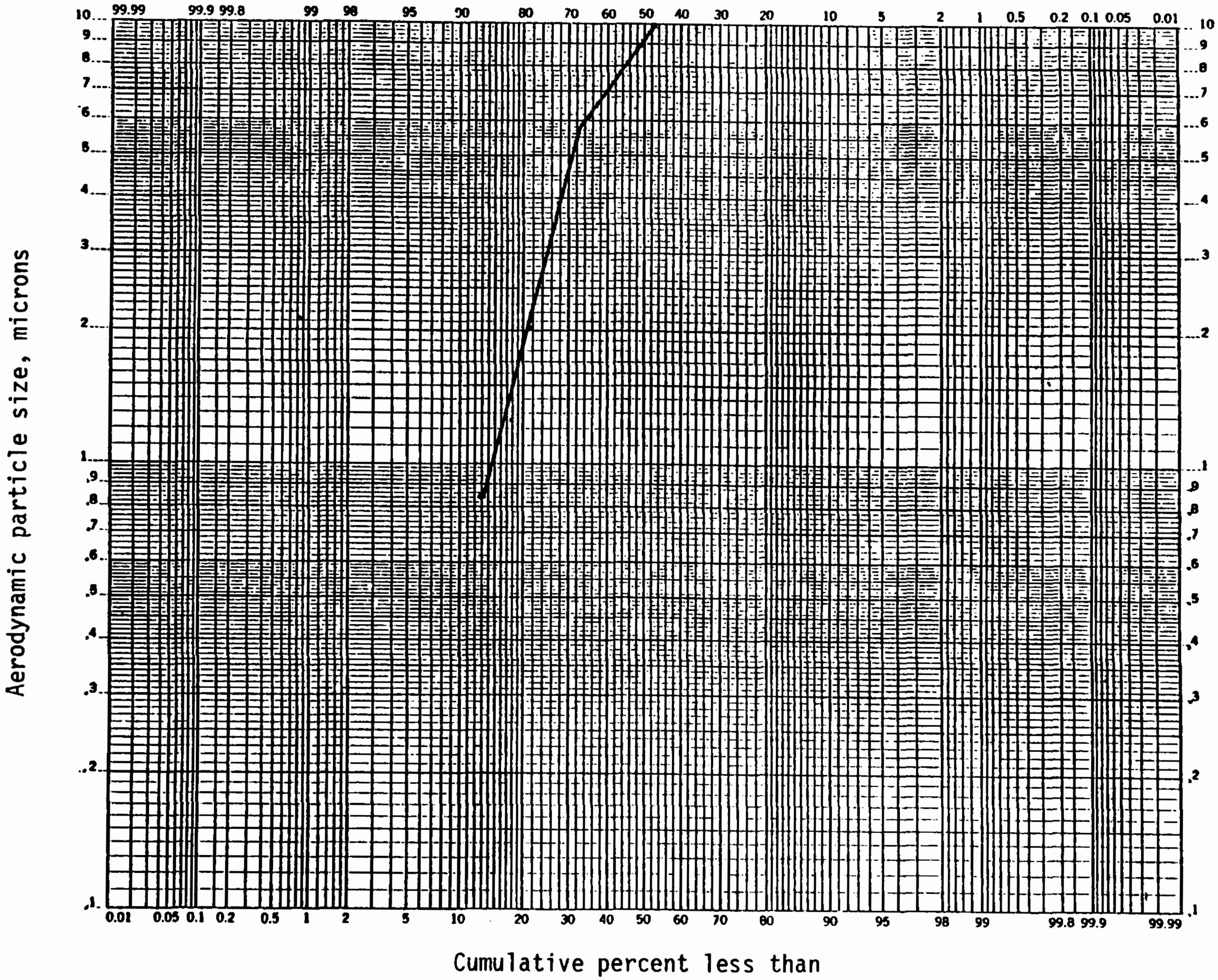

Figure 3-5. Particle size distribution of uncontrolled PM emissions from a wood-fired spreader stoker boiler.[32]

Figure 3-4 also shows an energy balance for the selected wood-fired boiler. This balance is based on fuel energy input from the wood waste and on steam output and various heat losses. Since a wood-fired boiler of the spreader stoker type firing a 50 percent moisture (wet basis) fuel is typically 65 percent efficient overall, total heat loss is 35 percent of the heat input, or 15.4 MW (52.5 x 10^6 Btu/hr) for this boiler. This overall efficiency includes a 98 percent combustion efficiency, based on typical boiler specifications that limit the amount of unburned fuel to 2.0 percent with cinder reinjection.[34]

Uncontrolled emissions for several representative wood and wood/coal boilers are presented in Table 3-4. These emissions rates were calculated using the bases and assumptions shown in Table 3-5.

3.2.1.2 Factors Influencing Uncontrolled Emissions. Three major factors influence uncontrolled emissions from wood-fired boilers: boiler design, fuel quality, and boiler operation.

3.2.1.2.1 Type of Boiler. Although the spreader stoker boiler is the most common firing method of the boilers burning wood waste, it is not the only method used. Overfeed stoker firing, fuel cells, suspension firing, and fluidized bed combustion (FBC) are also used to fire wood, though to a lesser degree than spreader stoker firing. A sixth type of firing method, the Dutch oven, was phased out (for new construction) in the 1950's because of its high construction cost, low efficiency, and inability to follow load swings.[37]

Spreader stoker boilers are currently used to burn wood waste because of their ease of operation and relatively high thermal efficiency, typically 65-70 percent of the energy available in the fuel. As shown in Table 3-2, all boilers from 1970 to 1978 sold with a steam capacity greater than 45,400 kg/hr (100,000 lb/hr) were either spreader stoker or overfeed stoker types. Spreader stokers can burn fuel with moisture contents up to 62-65 percent.[38] Above this they cannot support stable combustion unless an auxiliary fossil fuel is used.

The overfeed stoker is similar to the spreader stoker except fuel is spread across the furnace by a moving grate, rather than being thrown across

TABLE 3-4. EMISSIONS FROM REPRESENTATIVE WOOD AND WOOD/COAL FIRED SPREADER STOKER BOILERS[35]

Fuel[a]	Capacity (thermal input)	Pollutant[d]	Mass kg/hr (lb/hr)	Concentration[b] g/Nm^3 (gr/dscf)	Heat Input ng/J (lb/10^6 Btu)
		PM (BMC)	332 (732)	4.97 (2.17)	2090 (4.88)
	44 MW	PM (AMC)	66.4 (146)	0.993 (0.434)	418 (0.973)
Wood	(150 x 10^6 Btu/hr)	SO_2[e]		-	
		NO_x	17.0 (37.5)	133[c]	107 (0.250)
		PM (BMC)	467 (1030)	7.00 (3.06)	2950 (6.87)
	44 MW	PM (AMC)	93.9 (207)	1.40 (0.612)	592 (1.38)
HAB	(150 x 10^6 Btu/hr)	SO_2[e]	-	-	-
		NO_x	17.0 (37.5)	133[c]	107 (0.250)
	44 MW	PM (BMC)	411 (905)	6.13 (2.68)	2590 (6.03)
SLW	(150 x 10^6 Btu/hr)	PM (AMC)	142 (314)	2.12 (0.930)	899 (2.09)
		SO_2[e]	-	-	
		NO_x	17.0 (37.5)	133[c]	107 (0.250)
		PM (BMC)	348 (767)	5.26 (2.30)	2200 (5.11)
75% Wood/	44 MW	PM (AMC)	69.6 (153)	1.05 (0.461)	438 (1.02)
25% HSE	(150 x 10^6 Btu/hr)	SO_2	102 (224)	576[c]	639 (1.49)
		NO_x	23.5 (51.7)	185[c]	148 (0.344)
		PM (BMC)	364 (803)	5.63 (2.46)	2300 (5.35)
50% Wood/	44 MW	PM (AMC)	72.8 (160)	1.13 (0.493)	460 (1.07)
50% HSE	(150 x 10^6 Btu/hr)	SO_2	197 (434)	1140[c]	1240 (2.89)
		NO_x	29.9 (66.0)	242[c]	189 (0.440)
		PM (BMC)	290 (640)	4.32 (1.89)	1840 (4.27)
50% Wood/	44 MW	PM (AMC)	58 (128)	0.863 (0.377)	366 (0.853)
50% LSW	(150 x 10^6 Btu/hr)	SO_2	43.5 (95.8)	242[c]	274 (0.639)
		NO_x	29.9 (66.0)	232[c]	189 (0.440)

[a]Wood - Hog Fuel (wood/bark misture)
HAB - High Ash Bark
SLW - Salt Laden Wood
HSE - High Sulfur Eastern Coal
LSW - Low Sulfur Western Coal

[b]Corrected to 12 percent CO_2

[c]Gaseous emissions are in parts per million (ppm)

[d]BMC - before multicyclone
AMC - after multicyclone
Both values are listed since these boilers include flyash reinjection.

[e]The SO_2 emission rate for boilers firing 100 percent wood derived fuels is negligible. Available test data have shown emissions ranging up to 8.6 ng/J (0.02 lb/10^6Btu), but for many test runs, SO_2 emissions were below the detection level for the applicable EPA test method.

TABLE 3-5. BASES AND ASSUMPTIONS FOR WOOD AND WOOD/COAL FIRED BOILER ENERGY AND MATERIAL BALANCES[36]

Basis/Assumption	Value Used for Wood	Value Used for Wood/Coal
Unburned Fuel	3% of fuel as fired[a]	all the coal burns; unburned wood fuel basis is unchanged
Boiler Bottom Ash	50% of fuel ash input and 5% of the unburned combustibles[d]	sum of wood and coal[b]
Excess Air	50%	50%
Boiler Efficiency	65%	73% for 50% wood/50% coal 69% for 75% wood/25% coal
Fly Ash Reinjection	- all the mechanical collector catch is sand classified - reinjected material is mostly carbon - half the reinjected material burns; the rest is entrained in the flue gas - reinjection reduces total unburned fuel to 2% - all material not reinjected comes out the bottom of the sand classifier	- all the mechanical collector catch is sand classified - reinjected material is mostly carbon - half the reinjected material burns; the rest is entrained in the flue gas - reinjection reduces total unburned wood fuel to 2% - all material not reinjected comes out the bottom of the sand classifier (including all of the collected coal fly ash)
Mechanical Collector Efficiency	80%[d]	80%
PM Emissions Before Mechanical Collector	40% of fuel ash input 95% of unburned combustibles 50% of the reinjected material[c,d]	sum of wood and coal[b]
SO_2 Emissions	negligible	sum of wood and coal[b]
NO_x Emissions	0.25 lb/10^6 Btu[c]	sum of wood and coal[b]

[a]Since the fuel is 50 percent moisture (wet basis) and the unburned fuel is assumed to be mostly carbon, the actual mass rate of unburned combustibles is 1.5 percent of the fuel feed rate. A portion of these combustibles are ultimately burned through fly ash reinjection.

[b]This means that the mass rate of this stream was calculated using a weighted average of the stream based on firing wood alone and firing coal alone. All coal stream rates came from Fossil Fuel Fired Industrial Boilers - Background Information for Proposed Standards and were based on AP-42 emission factors. Averaging of emission rates from wood and coal fired boilers was generally based on engineering judgement.

[c]Since little test data were found for PM emissions prior to the mechanical collector, the PM emission rate was based on discussions with industry and academic personnel. The SO_2 emission rate was based on EPA and industry test data. The NO_x emission rate was based on data from an industry test program. More details about all of the bases in this table are provided in Reference 36.

[d]For salt-laden wood 100 percent of the salt was assumed to be entrained in the flue gas, and none of the salt was assumed to be collected in the mechanical collector.

the furnace by pneumatic or mechanical action of a fuel spreader. This reduces the amount of fuel burned in suspension and decreases the PM emission rate since there is less chance for particulate entrainment.

Some boilers have provisions to feed the smaller fuel particles in separate feed systems especially designed to handle these particles. These systems burn the smaller fuel particles in suspension above the grate. An advantage of this system is possibly better combustion of the smaller fuel particles than is obtained by mixing them with the larger size fuel. This system may also have an independent air supply to provide for better control of combustion air. Some types of wood fuel, such as sanderdust, burn rapidly and unless sufficient air is supplied in the right place the fuel will not burn completely. This unburned fuel will be entrained in the flue gas and increase PM emissions.

Fuel cell boilers range in size from 1360 kg/hr (3000 lb/hr) to 27,200 kg/hr (60,000 lb/hr) of steam, though multiple boilers may be used to provide larger capacities.[39] In this boiler, wood fuel is piled on a stationary grate in a refractory lined cell. Forced draft air is supplied to drive off the volatiles in the wood and burn the carbon. The volatiles are mixed with secondary and tertiary combustion air above the fuel pile, and pass into a second chamber where combustion is completed. This two stage combustion process gives lower PM emissions compared to spreader stoker boilers by reducing fuel entrainment.

Suspension-firing boilers differ from spreader stokers in that small-size fuel [normally smaller than 1.6 mm (0.06 in)] is blown into the boiler and combusted by supporting it on air rather than on fixed grates. Since grates are not required, capital costs for combustion equipment are lower and maintenance requirements are less since grate cleaning is unnecessary. Rapid changes in combustion rate and therefore steam generation rate are possible because the finely divided fuel particles burn very quickly. Another advantage is that ash is easily removed from the furnace bottom. The disadvantages include: (1) restrictive requirements regarding fuel particle size and moisture content (30 percent or less on a wet basis)[40] and (2) most of the ash is entrained in the flue gas.[41]

These boilers typically use a small size fuel (such as sanderdust) generated as a by-product of wood processing operations.[42] These fuels are typically cleaner and drier than other types of wood fuels. This can result in increased combustion efficiency and less ash entering the furnace which should lower uncontrolled particulate emissions. As shown by recent sales data (see Table 3-2) these types of boilers are only sold in the small size ranges.

A recent development in wood firing is the FBC process. A fluidized bed consists of inert particles through which air is blown so that the bed behaves as a fluid. Wood waste enters in the space above the bed and burns both in suspension and in the bed. Because the inert particles essentially create a completely lined refractory chamber, fluidized beds can handle fuels with moisture contents up to 67 percent (wet basis),[43] as compared with a maximum moisture content of 62-65 percent for a spreader stoker. Fluidized beds can also handle dirty fuels (up to 30 percent inert material).[44] Because of its contact with the hot inert bed material, the wood fuel is pyrolyzed faster in a fluidized bed than on a grate. As a result, combustion is rapid and results in nearly complete combustion of the organic material, thereby minimizing emissions of unburned combustibles.[45] This should lower PM emission rates for fluidized bed boilers compared to spreader stokers burning the same fuels, since the uncontrolled PM emissions from spreader stokers are normally over 50 percent unburned combustibles.[46]

The disadvantages of fluidized beds include slightly lower thermal efficiency compared to spreader stokers (approximately 60 percent and 65 percent respectively), higher pressure drops (10-15 kPa or 40-60 inches of water), higher operating costs, and larger amounts of excess air to keep the bed temperature less than the ash fusion temperature.[47] Only a few fluidized beds are used currently, but they are expected to become more common during the next decade, especially for low capacity units, because of their ability to burn fuels with high moisture and ash contents. Fluidized beds are presently built in sizes up to 35.2 MW (120 x 10^6 Btu/hr).[48]

Wood-fired boilers can also be of either watertube or firetube design. A watertube design boiler was shown in Figure 3-4. In firetube boilers, the hot gas flows through tubes and the water being heated circulates outside the tubes. Firetube boilers are usually limited in size to less than 8.8 MW (30×10^6 Btu/hr) thermal input. However, some firetube designs have been built with heat input rates up to 14 MW (50×10^6 Btu/hr).[49] Firetube boilers are commonly used in the furniture industry. The firing methods previously discussed can be used with firetube or watertube boilers.

3.2.1.2.2 Fuel Quality. Another factor influencing uncontrolled emissions from wood-fired boilers is fuel quality. Fuel quality is dependent upon the moisture content of the wood, the size of the wood fuel, harvesting and storage of the wood, and its preparation before it is introduced into the fuel chute.

Fuel moisture content is one of the most important factors affecting fuel quality. While most wood fuels show little variation in heating value on a dry basis, the variation in moisture content of wood waste, shown in Table 3-6, causes wide variations in heating value as fired. Higher fuel moisture contents reduce the fuel heating value, reduce overall boiler thermal efficiency, and retard combustion. This means that a higher fuel feed rate will be required for a given steam production.

In addition, because the moisture in the fuel evaporates during combustion, it increases the gas velocity in the combustion zone. This leads to the entrainment of more fuel particles and reduced residence time for combustion. Therefore, the effect of an increase in fuel moisture content will be an increase in particulate matter emissions.[131]

Also, rapid variations in fuel moisture content make control of combustion air difficult. This may result in less than optimum combustion conditions and an increase in unburned combustibles in the flyash.[50]

The initial fuel size distribution can be as important as the fuel analysis in affecting PM emissions.[52] Typical wood fuel is sized in a "hog" which reduces the size to less than four inches. The wood from the hog may be mixed with additional fuel which has already been reduced in size such as sawdust and shavings. When fired, smaller fuel particles are entrained in the flue gas. As the average fuel size decreases, more particles become entrained. These particles may escape the boiler before complete burnout

TABLE 3-6. RANGE OF MOISTURE CONTENT OF TYPICAL WOOD FUELS[51]

Fuel	Moisture content, (%) wet basis
Bark	25-75
Coarse wood residues	30-60
Planer shavings	16-40
Sawdust	25-40
Sanderdust	2-8
Reject "mat furnish"	4-8

resulting in increased PM emissions. The larger fuel particles tend to burn on the grate.[53]

Harvesting and storage methods before burning also affect PM emissions. In typical logging operations, dirt is picked up in the wood bark. The amount of dirt picked up is dependent on the type of soil and the weather conditions. This dirt may remain in the bark during processing of the raw wood and end up in the wood fuel. For this reason bark will usually have a higher ash content than other types of wood fuels. Outside storage of wood fuel can also cause dirt to be mixed with the fuel and thus be introduced into the combustion chamber. In addition to directly increasing the ash and PM emissions, this dirt can cause a reduction in combustion temperature, resulting in incomplete combustion and additional ash accumulations. Storage of wood fuel in high moisture conditions for a long period of time can also decrease the fuel heating value up to 7 percent.[54] Table 3-4 shows a calculated emission rate for high ash bark, which represents a wood fuel containing additional ash from storage or logging operations.

In typical logging operations in the northwestern United States, logs are stored in salt water. Consequently, both bark and logs may have a salt content of approximately 1 percent (dry basis) and a moisture content near 60 percent (wet basis). Combustion of wood and bark waste from logs stored in this manner, results in uncontrolled particulate emissions containing approximately 20 percent salt. These salt particles are typically submicron in size.[55] An example of this type of fuel is shown in Table 3-3. Emissions from salt-laden wood are shown in Table 3-4.

The effect of high moisture content in wood waste fuels on emissions (because of wood type or storage method) can be overcome by drying before combustion. One method of drying wood waste fuel is to use the heat discharged with the stack gases in a fuel dryer. The fuel can be dried to any degree desired. However, moisture levels below 25-30 percent (wet basis) may result in high combustion chamber temperatures and the possibility of grate damage.[56] Other methods such as vibrating off water or pressing the fuel are only effective at moisture levels above 60 and 50 percent respectively.

The analyses in Table 3-3 also show typical wood fuels to have low quantities of sulfur present in comparison to the quantities typically present in coal. Wood fuel nitrogen contents can range from as low as 0.04 percent up to 0.77 percent (dry basis).[136] However, on the average the nitrogen content is less than 0.22 percent.[136] This is lower than the nitrogen content of most coals. The low nitrogen and sulfur contents contribute to the low SO_2 and NO_x emissions resulting from wood combustion compared to the emissions resulting from the firing of coal.

Poor quality wood fuels may require cofiring fossil fuels with wood in wood-fired boilers. The effects of this practice are discussed in the section on boiler operation.

3.2.1.2.3 Boiler operation. The third factor influencing uncontrolled emissions from wood-fired boilers is the mode of operation of the boiler. Several operational practices cause variations in boiler emissions. The first involves firing fossil fuels in wood-fired boilers. Approximately 50 percent of wood-fired boilers have some type of fossil fuel firing capability.[57] Typically the fuels used are coal, fuel oil, or natural gas. Fossil fuels may be fired during boiler startup, or as an augmentation fuel and may be fired alone, or cofired with wood.

Startup operations vary with the operator and size of the boiler, but typically last no more than four hours.[58] Augmentation of wood with fossil fuels may occur when steam demands exceed the boiler capacity on wood alone, to compensate for higher than normal moisture contents in the wood fuel, or to maintain steam production when the wood feed system is inoperative or when enough wood fuel is unavailable.

The duration and frequency of the use of fossil fuels will vary. Data from an industry survey indicated that the majority of wood-fired boilers smaller than 45,000 kg/hr (100,000 lb/hr) of steam capacity obtain less than 25 percent of their annual heat input from fossil fuels.[59] These boilers are mainly located at solid wood products facilities. For existing boilers larger than 45,000 kg/hr (100,000 lb/hr) the percentage of total heat input from fossil fuel increases. However, the majority of new wood-fired boilers of all sizes will obtain 25 percent of less of their total heat input from fossil fuels on an annual basis.[60] The amount of fossil fuel fired at any specific time, however, may vary considerably.

The effect on PM emissions of firing fossil fuels in wood-fired boilers will vary according to the fuel used. Oil combustion results in smaller quantities of PM emissions than does wood combustion for a constant heat input so PM emissions will decrease with increased oil firing. With increased coal firing, PM emissions may increase or decrease depending on the coal ash content and the extent to which coal affects the wood combustion efficiency. The effects of firing coal with wood on PM emissions for two types of coal are shown in Table 3-4.

Increased fossil fuel firing will also affect emissions of other pollutants. Coal and residual oil have higher sulfur contents than wood fuels. Thus, emissions of SO_2 will increase in proportion to the sulfur content of the fuel mixture relative to wood alone. Also NO_x emissions may increase with coal and residual oil firing due to increased fuel bound nitrogen. The quantity of NO_x emissions resulting from firing fossil and nonfossil fuels can be estimated by averaging the amounts of NO_x produced from firing each type of fuel alone.[61] Increased natural gas firing will not increase PM or SO_2 emissions due to its low ash and sulfur contents. NO_x could potentially increase or decrease depending on changes in peak flame temperature, flame turbulence, or bulk furnace heat release rate incurred by natural gas addition.

Fly ash reinjection is the second operational factor which has a direct effect on PM emissions from the boiler. Fly ash reinjection consists of taking the PM collected in the mechanical collectors and injecting it back into the furnace. This is done for two reasons:

1) To increase overall boiler efficiency (increases range from 1 to 4 percent),[62] and
2) To reduce the amount of solid waste needing disposal.

The disadvantage is that this increases the uncontrolled PM emissions to the mechanical collector.[63,64] New boiler installations typically separate the collected PM into large and small fractions in sand classifiers. The larger particles, which are mostly carbon, are reinjected into the furnace. The smaller particles, mostly inorganic ash and sand, are discarded. For the representative spreader stoker boiler shown in Figure 3-4, 45 percent of the fly ash collected by the mechanical collector is reinjected. This increases emissions prior to the mechanical collector by a factor of 1.22.[65]

Varying the excess air in wood-fired boilers also influences uncontrolled emissions. Excess air is necessary for proper combustion, but too much can be detrimental to the combustion system. Optimum rates for new boilers usually range from 25 to 50 percent excess air depending on boiler design and fuel.[66] The detrimental effects of too much combustion air include:

- Reducing combustion temperatures and retarding the combustion rate;
- Reducing thermal efficiency, thus requiring more fuel for a given steam output; and
- Increasing gas velocities in the furnace causing transport of fuel particles out of the furnace before complete combustion.[67]

The effects of too much combustion air on uncontrolled PM emissions are most significant if it is injected as undergrate air. Increasing undergrate air directly affects the upward furnace gas velocities and increases fuel and particle entrainment.

The rate of steam production also affects the concentration of PM emissions in the flue gas. If steam production is increased the fuel feed rate also has to increase. This introduces more ash into the furnace and more fuel is entrained in the flue gas.

Operating the boiler outside its design steam production range results in increased uncontrolled emissions. Boilers are designed to operate within a certain range of firing rates. If actual loads are outside that range, combustion conditions may be upset by equipment limitations.[68] The combustion conditions will be less than optimum, resulting in decreased combustion efficiency and increased PM emissions.

Another operating practice that causes variations in wood-fired boiler emissions is the boiler's peak combustion temperature. Although this temperature cannot be varied as easily as excess air, the boiler's combustion temperature does influence emissions of nitrogen oxides (NO_x). A typical wood-fired boiler is designed to combust wood at approximately 1090°C (2000°F).[69] At this temperature, the total amount of NO_x from wood combustion is less then 107 ng/J (0.25 lb/10^6 Btu).[70]

Cofiring fossil fuels with wood increases the combustion temperature and may increase thermal NO_x formation in addition to increasing NO_x formation from fuel bound nitrogen. The NO_x emissions from two boilers burning approximately 25 percent wood/75 percent coal showed an average uncontrolled NO_x emission rate of 210 ng/J (0.48 lb/10^6 Btu).[71] This is well above the 110 ng/J (0.25 lb/10^6 Btu) emission rate of wood alone.

3.2.2 Bagasse-Fired Boilers

3.2.2.1 Facility Description. Bagasse-fired boilers are located at sugar mills, and the steam output is used to power the sugar cane processing equipment.[72] The methods used for firing bagasse to generate steam in existing boilers have been pile burning designs (fuel cell, horseshoe) and the spreader stoker. The pile burning designs have been considered to be the most reliable, flexible, and most simple firing methods available for bagasse.[73] However, because these designs require more operating labor, and are less efficient, recent trends have been toward using the spreader stoker.[74]

Figure 3-6 shows a schematic of a representative bagasse-fired spreader stoker boiler with a heat input capacity of 58.6 MW (200 x 10^6 Btu/hr). The design of bagasse spreader stoker boilers is the same as that of wood-fired boilers except that cinder reinjection is not normally used.[76] The general description of wood-fired boiler operation is also applicable to typical bagasse-fired spreader stoker boilers.

This figure shows material balances for the representative bagasse-fired boiler. Bagasse entering the boiler usually contains about 52 weight percent moisture (wet basis) and has an ultimate analysis similar to that shown in Table 3-7. The ultimate analysis of bagasse shown in the table was used to calculate the material and energy balances shown for this boiler.

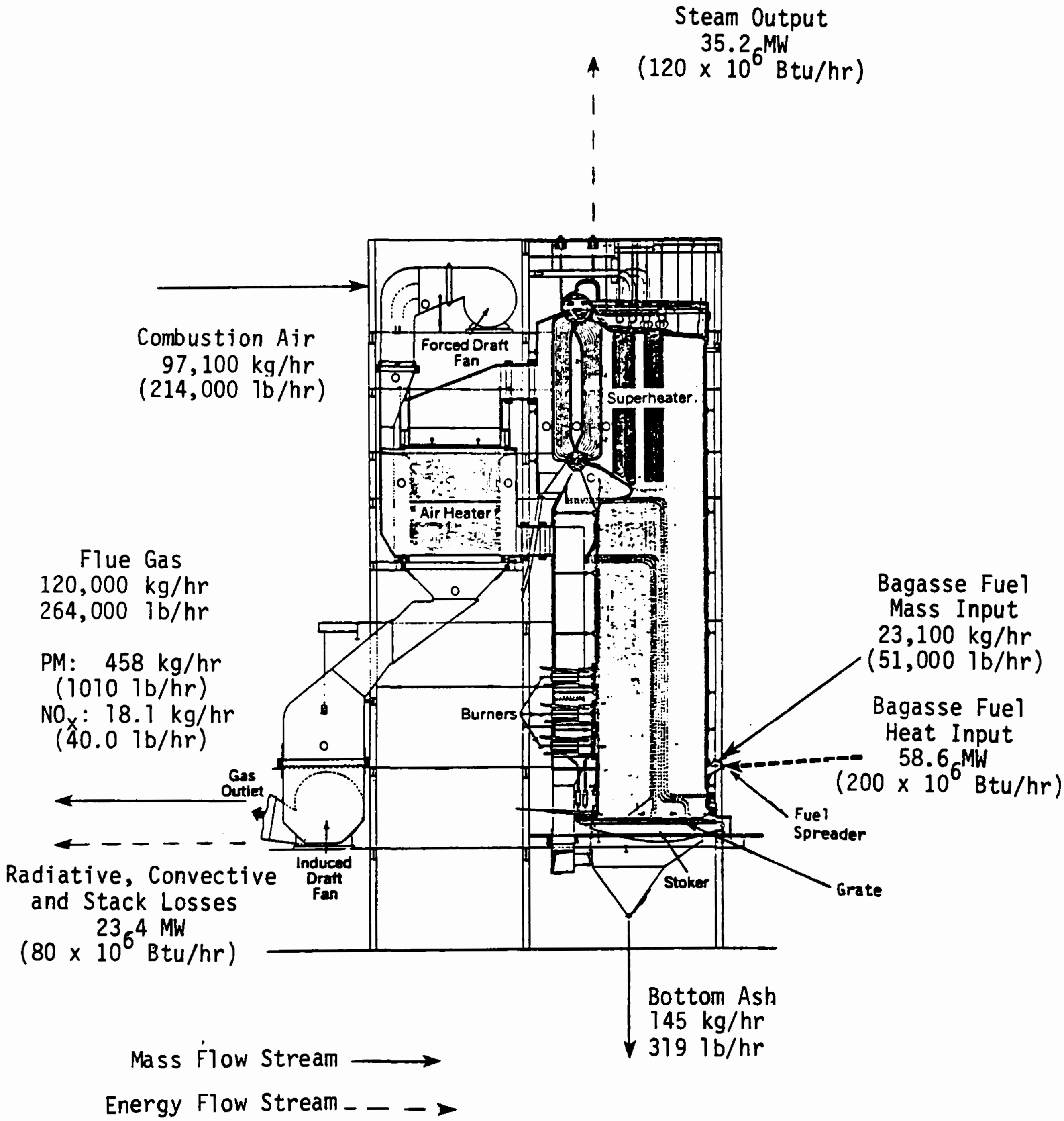

Figure 3-6. Material and energy balances for a representative bagasse-fired boiler.[75]

[*Steam: Its Generation and Use*, 39th ed., *The Babcock & Wilcox Company* (New York, 1978)] p. 11-4.

TABLE 3-7. BAGASSE ANALYSIS SELECTED FOR REPRESENTATIVE BOILERS[77,78]

Material	Percentage (dry basis)	Percentage (as fired)
Carbon	47.0	22.6
Hydrogen	6.5	3.1
Oxygen	44.0	21.10
Nitrogen	0.2	0.1
Sulfur	trace	trace
Water	-	52.0
Ash	2.3	1.1
Total	100.0	100.0
Higher heating value kJ/kg (Btu/lb)	(8160)	(3920)

Bagasse combustion causes ash accumulation in the boiler ash pit and PM discharge with flue gas from the stack. Ash accumulation and flue gas discharge rates are shown in Figure 3-6 for the representative bagasse-fired boiler. Uncontrolled emissions are presented in Table 3-8 for this boiler. These emissions are based on combustion and mass balance calculations developed from the bases and assumptions shown in Table 3-9.

Figure 3-6 also shows an energy balance for the selected bagasse-fired boiler. This balance is based on (1) fuel energy input from the bagasse and (2) steam output and various heat losses. All heat losses are shown as a heat loss out of the stack. Since a spreader stoker boiler has an average of 60 percent efficiency overall when firing bagasse, total heat loss is 40 percent of the heat input, or 23.4 MW (80 x 10^6 Btu/hr).[81] Available energy input is 9120 kJ/kg (3920 Btu/lb) of bagasse. This low available energy in the bagasse partly results from the high moisture content (52 percent) of the fuel. Two size distribution curves for uncontrolled bagasse PM emissions from fuel cell furnaces are shown in Figure 3-7. Similar data are not available for uncontrolled emissions from a spreader stoker.

3.2.2.2 Factors Influencing Uncontrolled Emissions. Boiler type, fuel quality, and boiler operation influence the uncontrolled emissions from bagasse-fired boilers, as they do with wood-fired boilers. These three factors are discussed separately below.

3.2.2.2.1 Types of boilers. Fuel cells, horseshoes, and spreader stokers are used to combust bagasse. The horseshoe and fuel cell differ in the shape of the furnace area but in other respects are similar in design and operation. These are pile burning designs similar to the Dutch oven boiler used to burn wood. The basic design of the bagasse-fired spreader stoker boiler is the same as that of the wood-fired spreader stoker discussed previously and results in more suspension burning than the fuel cell or horseshoe. As with wood-fired boilers, increased suspension burning is expected to result in increased PM entrainment. Most new bagasse-fired boilers are expected to be spreader stokers.

TABLE 3-8. UNCONTROLLED EMISSIONS FROM A REPRESENTATIVE BAGASSE-FIRED SPREADER STOKER BOILER[79]

Capacity (thermal input)	Pollutant	Emissions: Mass kg/hr (lb/hr)	Emissions: Concentration[a] g/Nm^3 (gr/dscf)	Emissions: Heat Input ng/J ($lb/10^6$ Btu)
58.6 MW (200×10^6 Btu/hr)	PM	458 (1010)	5.24 (2.29)	2170 (5.05)
	NO_x	18.1 (40.0)	108[b]	86.0 (0.20)

[a]Corrected to 12 percent CO_2.

[b]NO_x concentration is in ppm.

TABLE 3-9. BASES AND ASSUMPTIONS FOR BAGASSE-FIRED BOILER ENERGY AND MATERIAL BALANCES[80]

Basis/Assumption	Value Used
Unburned Fuel	3% of fuel as fired; water is subtracted from the mass rate
Bottom Ash	50% of fuel ash input 5% of unburned combustibles
Excess Air	50%
Boiler Efficiency	60%
Uncontrolled PM Emissions[a]	50% of fuel ash input 95% of unburned combustibles
Uncontrolled SO_2 Emissions	negligible
Uncontrolled NO_x Emissions[a]	0.2 $lb/10^6$ Btu

[a]Since little uncontrolled PM emission data were found, the PM emission rate was based on discussions with boiler vendors. The NO_x emission rate was based on data from three emission tests. More details about the basis in this table are provided in Reference 80.

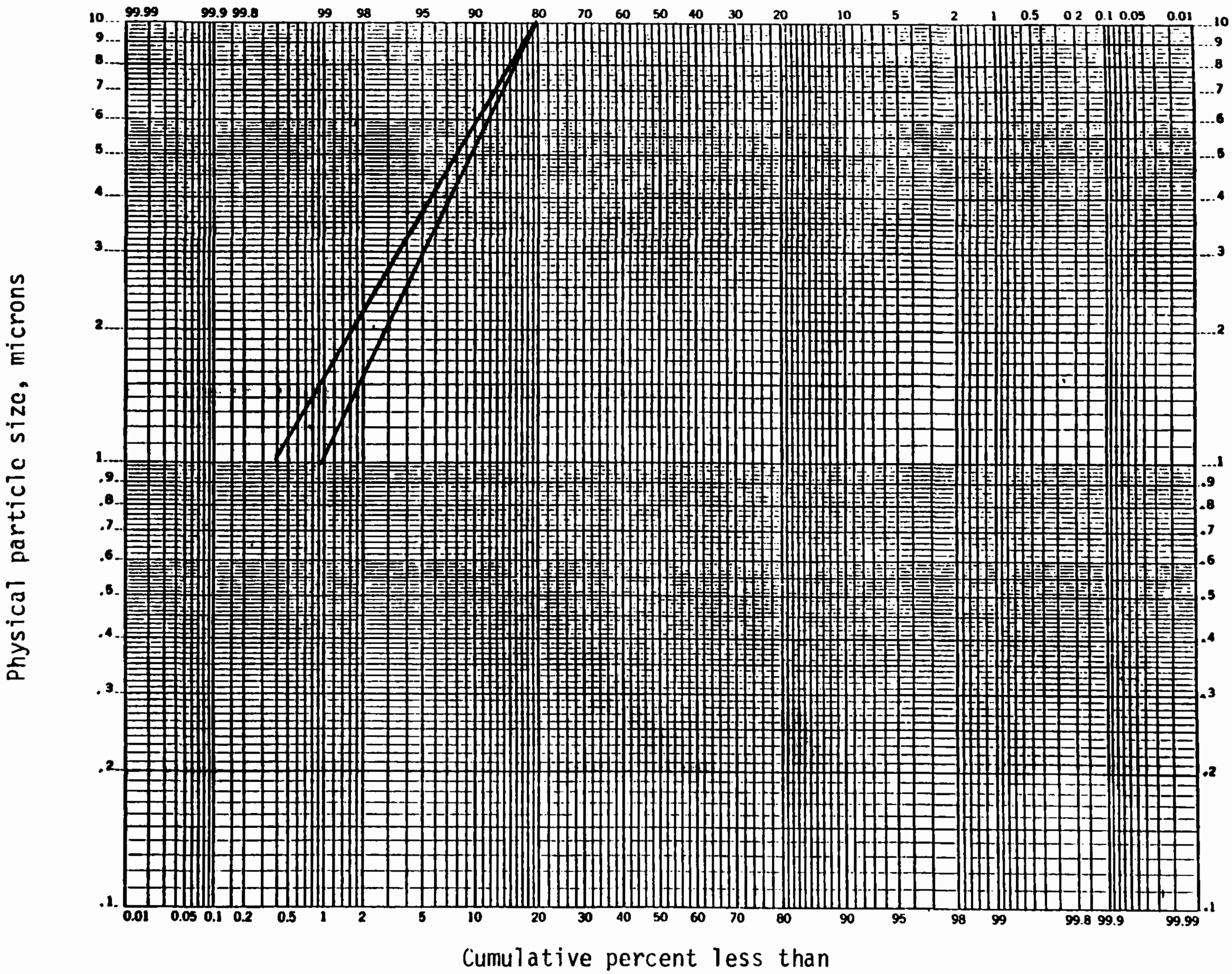

Figure 3-7. Particle size distribution of uncontrolled PM emissions from two fuel cell bagasse-fired boilers.[82]

3.2.2.2.2 Fuel quality. Samples of bagasse taken at different localities show almost identical analyses on a dry, ash free basis. However, the type of cane and harvesting and processing methods can affect the ash content, moisture content, and fuel particle size.

The harvesting and processing methods for sugar cane are affected by geographic location. For example, in Florida approximately 70 percent of the sugar cane is cut by hand and the remainder is harvested by machines.[83] In Hawaii all the sugar cane is machine harvested.[84] Machine harvesting increases the amount of dirt and trash mixed in with the cane. Because of this, all Hawaiian sugar mills have cane precleaning plants to remove the soil and trash from the cane.[132] This will also reduce the soil and trash remaining in the bagasse after the cane is processed. Some Hawaiian mills also use bagasse dryers to reduce the moisture content of the bagasse and additional bagasse dryers are planned in the future.[133]

Differences in harvesting, processing, and cane variety cause the bagasse moisture content at different sites to vary from 47 to 57 percent (wet basis). The lower bagasse moisture contents are generally found in Hawaii.[134]

Generally lower ash contents and moisture contents and larger fuel particle sizes tend to decrease PM emissions due to the same factors discussed previously for wood. Lower ash and moisture contents result in lower undergrate air and fuel feed rate requirements while larger fuel particle sizes are less easily entrained in the flue gas.

3.2.2.2.3 Boiler operation. Boiler operating procedures can influence uncontrolled emissions from bagasse-fired boilers. First, like other waste-fired boilers, bagasse boilers may use auxiliary fuels for startup. Because fuel oil is usually the startup fuel, the initial SO_2 and NO_x emissions are higher than when bagasse alone is fired. The duration of startup is up to 8 hours. During this time PM emissions may increase due to poor combustion conditions in the boiler while it is cold. In most areas bagasse boilers are started up once at the start of the harvest season and are not shut down unless it is absolutely necessary. The length of the harvesting season is also affected by geographic location and ranges from 3 months (Louisiana) to 10 months (Hawaii).

In Hawaii, the boilers are operated differently in that they are shut down on weekends unless they are cogenerating electricity for the local utility. Cogenerating boilers must operate continuously for 11 months of the year.[135] Also, bagasse-fired boilers in Hawaii are generally more efficient than in other areas due to generally lower fuel moisture contents, larger boiler sizes, and the placement of the stoker feed system higher above the grate to increase suspension burning.[84]

Second, most bagasse boilers may cofire an auxiliary fuel (normally fuel oil or natural gas) at times to produce the total energy needed for the facility or to sustain good combustion with wet bagasse. As is the case during startup, combined oil and bagasse firing will increase SO_2 and NO_x emissions. Auxiliary fuel is used whenever additional heat input is required. If the supply of bagasse to the boiler is interrupted auxiliary fuel will be used to provide up to 100 percent of the heat input of the boiler. During these periods the SO_2 and NO_x emissions will increase. Facilities burning bagasse attempt to keep auxiliary fuel use to a minimum. Typically less than 15 percent of the total annual fuel heat input into the boiler comes from fossil fuels.[85] Bagasse-fired boilers in Hawaii which cogenerate electricity will generally fire the largest amounts of fossil fuels because they are operated outside of the harvest season.[84]

Third, the peak combustion temperature influences NO_x emissions. Since bagasse boilers are similar in design and operation to wood-fired boilers, the furnace temperature would be expected to be similar also. Based on emission test data, total NO_x formation is about 86 ng/J (0.2 lb/10^6 Btu) unless auxiliary fuel is being burned.[86]

Other operational factors, such as excess air, should affect bagasse boilers in the same manner as wood-fired boilers based on the similarity of fuel and boiler design.

3.2.3 General Solid Waste-Fired Boilers

This section discusses MSW-, ISW- and RDF-fired boilers. Each subsection describes the common boiler types, fuel burned, and operational procedures which affect uncontrolled emissions.

3.2.3.1 Municipal Solid Waste-Fired Boilers. As previously mentioned in Section 3.1, MSW-fired boilers can be separated into two categories based on the boiler's heat input capacity. These categories are small modular units and large mass burning facilities.

3.2.3.1.1 Facility Description

3.2.3.1.1.1 Large "Mass Burn" MSW Facilities. Large MSW-fired boilers have been used in Europe since World War II, and over one hundred are currently operating there. However, this method of MSW disposal if relatively new to the United States and most of the existing facilities have been built since 1970.[87] A typical large MSW-burning facility is shown in Figure 3-8. This figure also presents material and energy balances for the boiler facility, based on combustion and mass balance calculations.

Combustion of MSW is generally accomplished in "mass burn" firing installations similar to that shown in Figure 3-8. This term refers to the minimal fuel preparation prior to firing. These installations are typically waterwall furnaces, which employ overfeed stokers. Traveling or reciprocating grates move the solid waste through the furnace and cause a tumbling action on the waste which results in more rapid ignition and better burnout.

In a typical large facility burning MSW, the waste is dumped from garbage trucks or compacted transport trucks into a large pit. An overhead crane is then used to load the waste from the pit to the feed chute. Fuel preparation consists of only limited mixing of the waste by the crane operator and removal of bulky items, such as telephone poles and box springs. The feed chute deposits solid waste on the first, or "dry-out", grate. Ignition starts at the bottom of the dry-out grate and is concentrated on the second, or "combustion" grate. The third grate, a "burn-out" grate, provides final combustion of the waste before the ash falls into the flooded ash pit.[89]

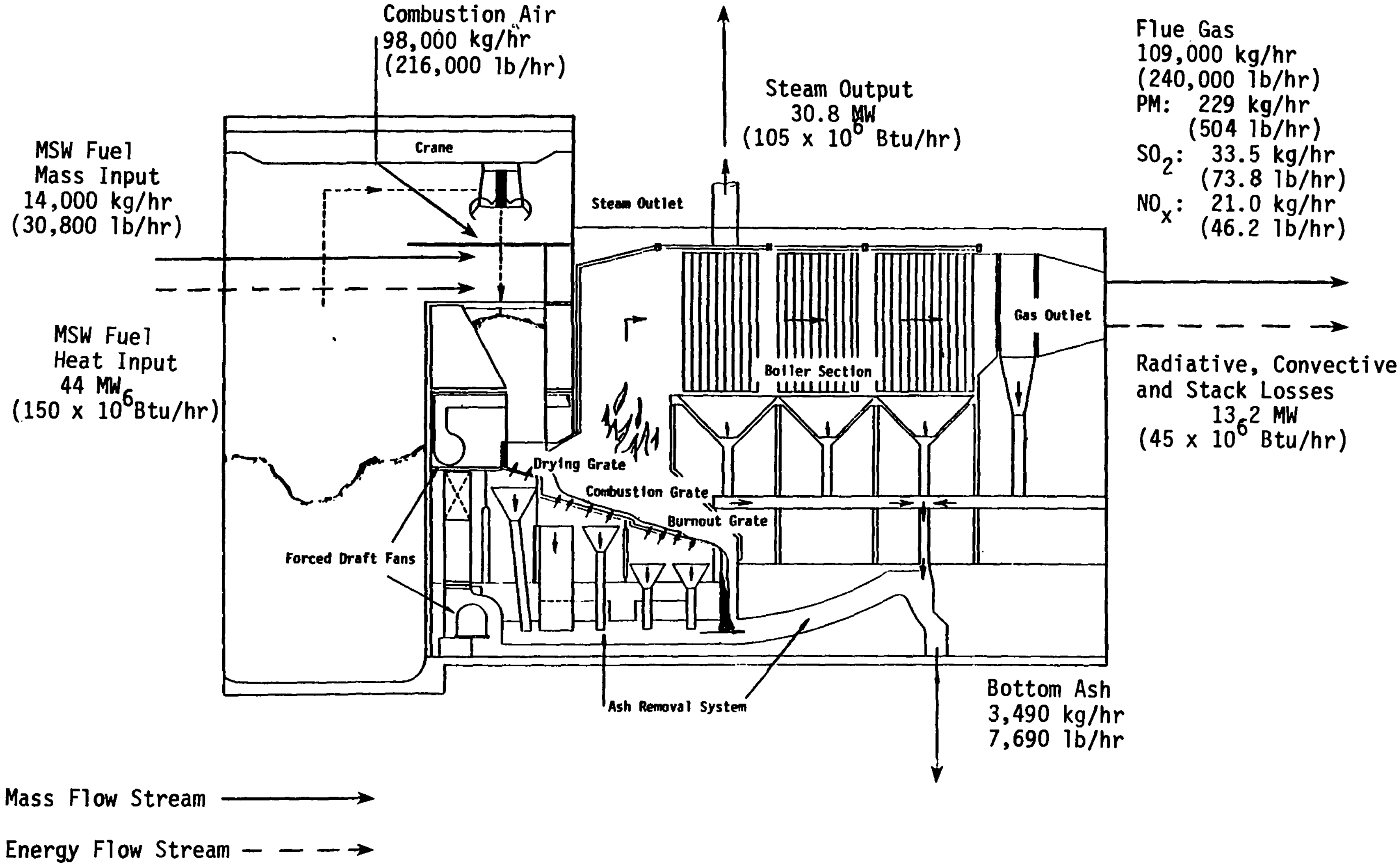

Figure 3-8. Energy and Material Balances for a Representative Large MSW-Fired Boiler[88]

The furnace operator controls the relative speeds of the three grates so that most of the combustion takes place on the second grate. These speeds are dependent upon both the waste combustion characteristics and moisture content. Ferrous metals are magnetically removed from the ash and sold, and the residue is landfilled.

The large MSW-fired boiler in Figure 3-8 combusts 14,000 kg/hr (30,800 lb/hr) of solid waste. The received and ultimate analyses of the representative MSW used in these material and energy balances are shown in Table 3-10. The available heating value of MSW is typically around 10,470 kJ/kg (4,500 Btu/lb).[91] However, since the average heating value is expected to increase in the future, as discussed in Section 3.1.2.3, a waste composition with a heating value of 11,340 kJ/kg (4,875 Btu/lb) from a performance test at a currently operating facility was used.[92] This analysis of this waste compares closely with reported "typical" compositions.[93] The basis and assumptions used to calculate the energy and material balances are shown in Table 3-11. Excess air for this facility is 100 percent.

An energy balance for the facility is also shown in Figure 3-8. The overall thermal efficiency of this boiler is 70 percent, which is typical for large MSW-firing operations.[95,96] Total heat loss is shown as loss out the stack and is 13.2 MW (45×10^6 Btu/hr), including heat transfer through equipment walls and heat loss in the flue gas.

The flue gas flow rate is 109,000 kg/hr (240,000 lb/hr), including 229 kg/hr (504 lb/hr) of PM. Uncontrolled emissions from this typical large MSW boiler and a small controlled air MSW boiler are presented in Table 3-12. Two size distributions of uncontrolled PM emissions for large MSW boilers are shown in Figure 3-9.

3.2.3.1.1.2 Small Modular Incinerators (SMI) With Heat Recovery. Combustion of MSW in small modular boilers was introduced in the late 1960's.[100] These units are shop fabricated on a package basis and are typically hopper and ram-fed instead of crane-fed as is the MSW boiler shown in Figure 3-8.[101] To provide ease of expansion in burning capacity for small towns and industries, the modular boiler system is designed to allow

TABLE 3-10. MUNICIPAL SOLID WASTE ANALYSIS SELECTED FOR REPRESENTATIVE BOILERS[90]

Material	Percentage (Dry basis)	Percentage (As fired)
Carbon	36.69	26.73
Hydrogen	4.94	3.60
Oxygen	27.09	19.74
Nitrogen	0.23	0.17
Sulfur	0.16	0.12
Chlorine	0.18	0.13
Water	-	27.14
Ash	30.72	22.38
Total	100.00	100.00
Higher Heating Value kJ/kg (Btu/lb)	15,560 (6,690)	11,340 (4,875)

TABLE 3-11. BASES AND ASSUMPTIONS FOR LARGE MSW-FIRED BOILERS[94]

Basis/Assumption	Value Used
Bottom Ash	25% of fuel feed rate (mass basis)
Excess Air	100%
Boiler Efficiency	70%
Uncontrolled PM Emissions[a]	1.6 gr/dscf corrected to 12% CO_2
Uncontrolled SO_2 Emissions[a]	100% conversion of sulfur in fuel
Uncontrolled NO_x Emissions[a]	3 lb NO_x/ton fuel burned

[a]The PM emission rate was based on test data from a few operating facilities. Complete conversion of fuel sulfur to SO_2 was assumed so as to provide an estimate of the maximum SO_2 emission rate. SO_2 emissions are fairly low, in any case, due to the low fuel sulfur content. The NO_x emission rate was based on an AP-42 emission factor. More details about all of the bases in this table are provided in Reference 94.

TABLE 3-12. UNCONTROLLED EMISSIONS FROM REPRESENTATIVE MSW-FIRED BOILERS[97]

Boiler Type	Capacity (thermal input)	Pollutant	Emissions: Mass kg/hr (lb/hr)	Emissions: Concentration[a] ng/Nm^3 (gr/dscf)	Emissions: Heat Input ng/J ($lb/10^6$ Btu)
Modular Controlled Air	2.9 MW ($10x10^6$ Btu/hr)	PM	1.36 (3.0)	3.25 (1.42)	129 (0.300)
		SO_2	2.23 (4.92)	201[b]	211 (0.492)
		NO_x	1.40 (3.08)	175[b]	132 (0.308)
Overfeed Stoker "Mass-burn"	44 MW ($150x10^6$ Btu/hr)	PM	229 (504)	3.66 (1.60)	1440 (3.36)
		SO_2	33.5 (73.8)	201[b]	211 (0.492)
		NO_x	21.0 (46.2)	175[b]	132 (0.308)

[a]At 12% CO_2.

[b]Gaseous concentrations are in ppm.

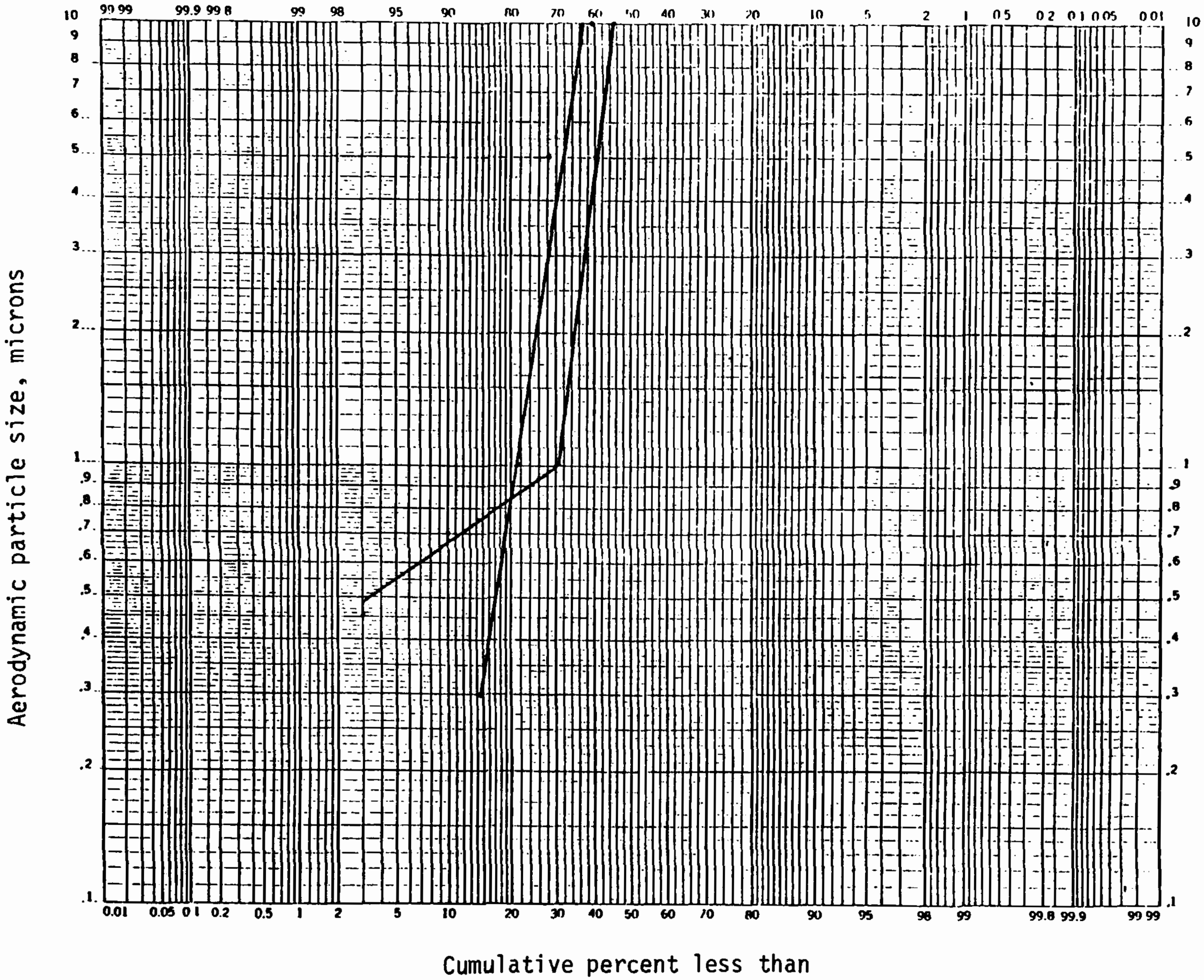

Figure 3-9. Particle size distribution of uncontrolled PM emissions from two large MSW-fired boilers.[98,99]

installation of additional units in modules as refuse generation increases.[102] These units typically have heat input capacities of 11.1 MW (38×10^6 Btu/hr) or less.

A typical small modular incinerator is shown in Figure 3-10. The boiler shown in this figure consists of an incinerator with a primary and secondary combustion chamber. Units of this type are commonly referred to as "controlled-air" or "starved-air" boilers because the air in the primary combustion chamber is below stoichiometric levels to minimize ash and fuel entrainment. Energy and material balances for this boiler are also shown in Figure 3-10 and are based on empirical data from performance tests. The bases and assumptions used for these calculations are shown in Table 3-13.

Small modular incinerators like that shown in Figure 3-10 typically combust refuse at around 820°C (1500°F) in the primary chamber and at 1000°C (1900°F) in the secondary chamber. The auxiliary burner shown in Figure 3-10 is an integral part of the controlled air boiler and is used whenever the secondary chamber temperature is below the set point.[105] A plot of the size distribution for uncontrolled PM (fly ash) from three controlled air boilers is shown in Figure 3-11.

3.2.3.1.2 Factors Influencing Uncontrolled Emissions. The factors that influence uncontrolled emissions from wood-fired boilers also influence the uncontrolled emissions from boilers burning MSW. Those factors are boiler type, fuel quality, and boiler operation.

3.2.3.1.2.1 Boiler type. Two types of boilers are currently used to combust MSW. The most common type is the mass burning stoker boiler shown in Figure 3-8. Boilers that mass burn are capable of burning solid waste fuels with large size variations. Because of this capability, normally the only fuel preparation is removal or sizing of large bulky items (such as furniture, etc.).

The other common boiler is the small modular boiler with multichamber controlled-air combustion, which is also designed to burn the waste without extensive fuel preparation. The small modular boiler has lower uncontrolled PM emissions. This results from the low air feed rate to the primary

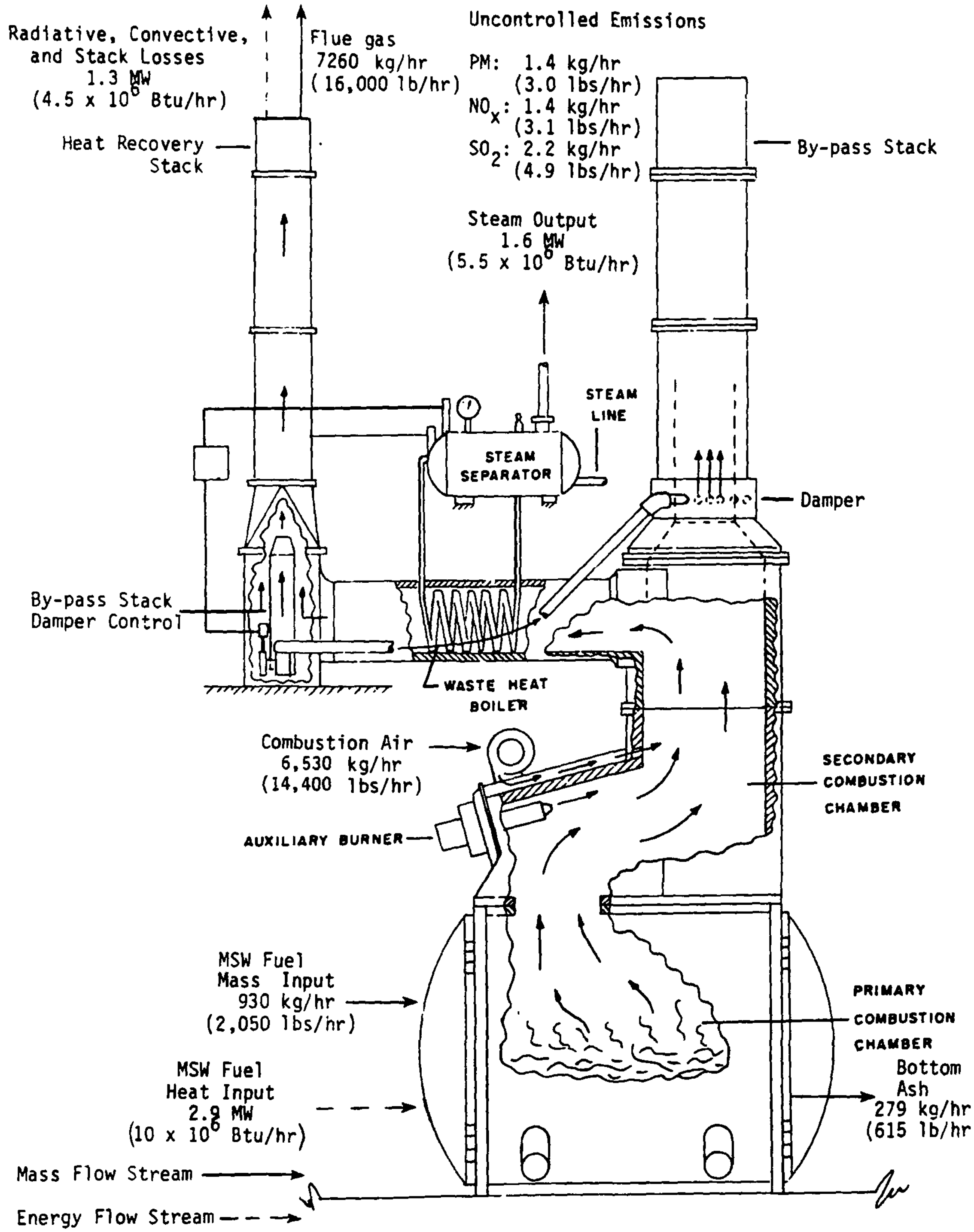

Figure 3-10. Energy and Material Balances for a Representive controlled air MSW-Fired Boiler.[103]

TABLE 3-13. BASES AND ASSUMPTIONS FOR SMALL CONTROLLED AIR MSW-FIRED BOILERS[104]

Basis/Assumption	Value Used
Bottom Ash	30% of fuel feed rate (mass basis)
Excess Air	100%
Boiler Efficiency	55%
Uncontrolled PM Emissions[a]	0.3 $lb/10^6$ Btu
Uncontrolled SO_2 Emissions[a]	100% conversion of sulfur in fuel
Uncontrolled NO_x Emissions[a]	3 lb NO_x/ton fuel burned

[a]The PM emission rate was based on a survey report of industry emission tests. Complete conversion of fuel sulfur to SO_2 was assumed so as to provide an estimate of the maximum SO_2 emission rate. SO_2 emissions are fairly low, in any case, due to the low fuel sulfur content. NO_x emissions were based on an AP-42 emission factor. More details about all of the basis in this table are provided in Reference 104.

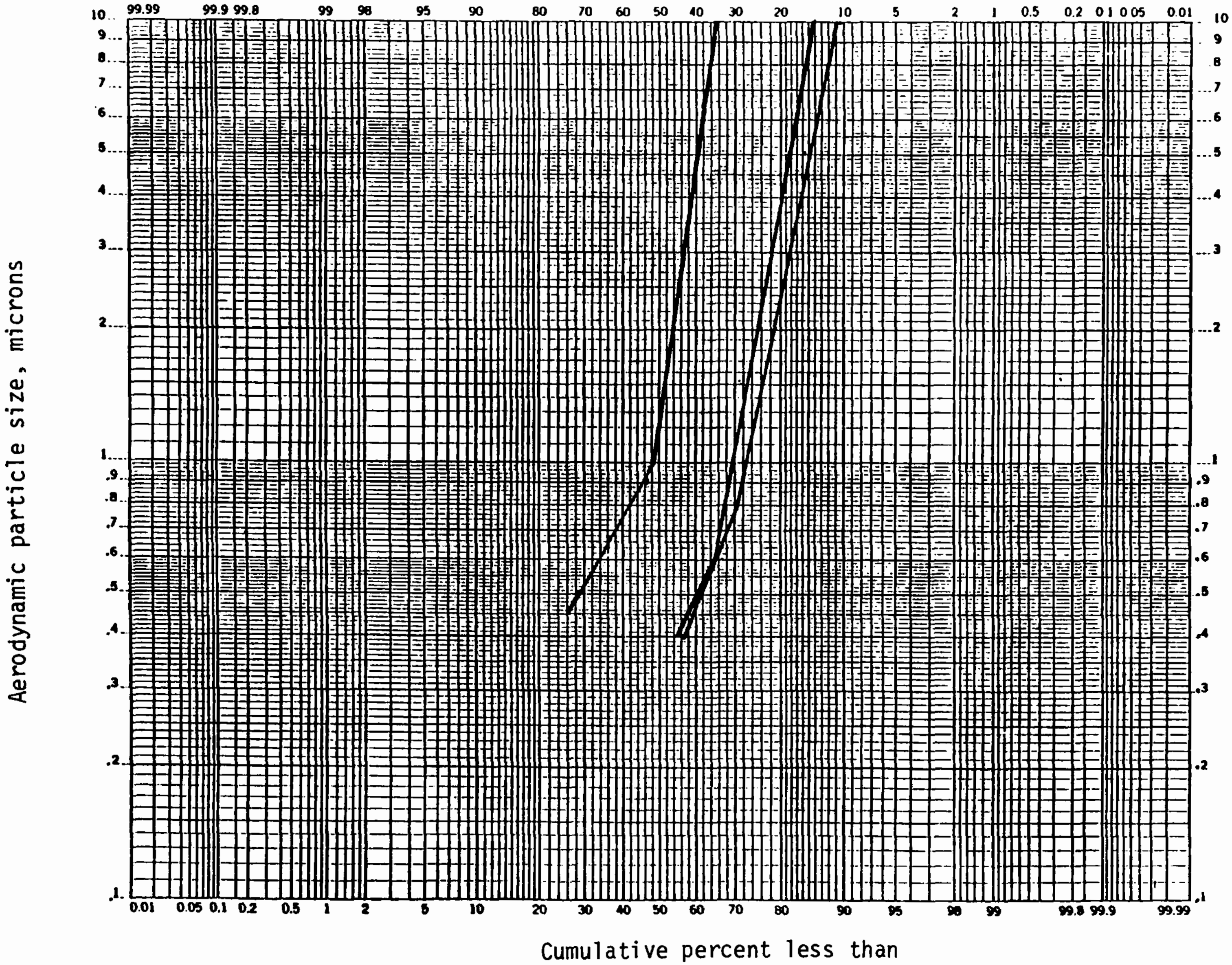

Figure 3-11. Particle size distribution of uncontrolled PM emissions from three small controlled air MSW-fired boilers.[106,107]

combustion chamber causing reduced entrainment of ash and unburned combustibles.

3.2.3.1.2.2 Fuel quality. Two factors related to fuel quality influence uncontrolled emissions from MSW-fired boilers. First, there are significant variations in the composition of MSW. For example, MSW composition is dependent on the net waste contribution of business offices, housefolds, and industrial waste producers. Seasonal variations are also common in the composition of MSW. For instance, yard waste in MSW ranges from 0.3 percent in winter to 23 percent in summer in the Northern states.[108] This seasonal variation in composition results in variations in ash content and heating value of the fuel. Lower heating values and higher ash contents will both increase emissions.

Cofiring of other fuels with MSW is the second fuel-related influence on uncontrolled emission levels from MSW boilers. In situations in which auxiliary fuels such as natural gas or fuel oil are required to augment the MSW input, NO_x emissions may increase because of increased flame temperatures and SO_2 emissions may increase if the fossil fuel has a higher sulfur content.[109] PM emissions should decrease based on the lower PM emission rate for oil or natural gas. Presently operating large MSW-fired boilers do not normally fire fossil fuels unless required to produce steam when the stoker system is inoperative.

3.2.3.1.2.3 Boiler operation. Three operations that influence uncontrolled emissions from the combustion of MSW are startup, excess air adjustments and the boiler's operating temperature. Startup of large MSW-fired boilers is usually accomplished by igniting the GSW directly. although in at least one facility oil is used prior to startup to preheat the PM emission control equipment. Startup for this facility is two hours in duration.[110] The small modular units are started by igniting the MSW in the primary chamber with fuel oil or gas. Once combustion is started these burners are turned off. The auxiliary burner in the second chamber is used until the temperature reaches the set point (about 815°C). The entire process takes 10 to 30 minutes in the primary chamber and up to one hour in the secondary chamber.[111] During this time, uncontrolled emissions will be affected as discussed previously for cofiring with fossil fuels. Increasing combustion air flow above design levels can increase PM emissions by increasing the amount of fuel entrained and carried out of the furnace area before combustion is complete.

The third operation that influences uncontrolled emissions of NO_x from MSW-fired boilers is the boiler's peak design combustion temperature. MSW-fired boilers are typically designed for a peak combustion temperature of 980°C (1800°F).[112] Because of the low temperature and the fuel's low nitrogen content, NO_x emissions are low, with a level of about 130 ng/J (0.30 lb/10^6 Btu).[113]

3.2.3.2 Industrial Solid Waste-Fired Boilers. ISW is presently burned in the same type of small controlled air boilers used to burn MSW which were described previously. The heat input capacities of these boilers ranges up to 17.6 MW (60 x 10^6 Btu/hr) when firing ISW. ISW could also be burned in the large mass burn facilities described previously. However, this has not been done except when the ISW is collected as part of municipal solid waste.

Table 3-14 whose a representative analysis of ISW. As shown in this table the average heating value for ISW is higher than MSW, and the ash content is less. Based on this analysis PM emissions from ISW should be less than those from MSW burned in the same type of boiler under similar conditions.

3.2.3.3 Refuse Derived Fuel-Fired Boilers. As previously mentioned, RDF can be cofired with coal or burned alone. Its heating value is approximately 1.2 times the heating value of MSW, or 13,500 kJ/kg (5,790 Btu/lb), due to the lower percentages of water and ash in the fuel. Mixtures of from 0 to 100 percent RDF (heat input basis) have been tested in coal fired spreader stoker boilers and mixtures of up to 27 percent in suspension firing (pulverized coal) units, though usual operation in the suspension unit is 20 percent RDF or less. To date, RDF has mostly been fired as a substitute for a portion of the coal in coal-fired boilers. But there are presently three facilities burning RDF alone in stoker fired units.[8]

TABLE 3-14. REPRESENTATIVE ANALYSIS OF INDUSTRIAL SOLID WASTE[114]

	Weight[a] Percent	Moisture	Volatile Matter	Sulfur	Inerts	HHV - dry kJ/kg	HHV - dry Btu/lb
CORRUGATED BOARD AND MISC. PAPER	52	8	75	0.2	5.0	17,710	7,600
HARDWOOD (Crates, Pallets, etc.)	28	12	67	0.1	3.0	19,340	8,300
TEXTILES	5	10	80	0.2	3.0	18,640	8,000
PLASTICS (Film and Rigid)	4	1	95	0.1	1.5	34,000	14,600
METALS	3	2	-	0.1	95.0	280	120
MISCELLANEOUS RUBBER	2	2	83	2.0	15.0	26,330	11,300
FOOD WASTES	1	50	20	0.5	5.0	19,570	8,400
SWEEPINGS	5	25	54	0.2	20.0	13,980	6,000
COMPOSITE WEIGHTED ANALYSIS[b]		10	70	0.2	8.0	18,170	7,800

CALORIFIC VALUE (HHV) ADJUSTED TO REFLECT COMPOSITE (10%) MOISTURE = 16,540 kJ/kg (7,100 Btu/lb).

[a]The glass constituent in general plant waste is expected to be less than 1%.

[b]The solid waste constituent mix and their discrete characteristics will vary from plant to plant in the same industry and probably even within the same company.

3.2.3.3.1 Facility Description. A representative RDF/coal cofired boiler is shown in Figure 3-12 along with material and energy balances. This boiler is a field-erected, watertube, spreader stoker unit rated at 44 MW (150 x 10^6 Btu/hr) of heat input. The bases and assumptions used in the calculations of these balances are presented in Table 3-15. The ultimate analyses of the fuel inputs are shown in Table 3-16. Uncontrolled PM emissions for this boiler were calculated based on the emission factors for 100 percent HSE coal firing, since the available test data did not show a significant difference in PM emissions for coal/RDF-firing as compared to coal alone. These emissions are compared with the emissions from a coal-fired boiler in Table 3-17. A size distribution curve for uncontrolled PM emissions from a boiler cofiring RDF and coal is presented in Figure 3-13.

3.2.3.2 Factors Influencing Uncontrolled Emissions. The same three factors influence uncontrolled emissions from boilers cofiring coal and RDF as those burning GSW: boiler type, fuel quality, and boiler operation.

3.2.3.2.1 Boiler type. Since most coal-fired boilers can potentially cofire RDF, the effect of boiler type on uncontrolled emissions should be similar for boilers firing either fuel. For example, suspension fired (pulverized coal) units cofiring RDF and coal would be expected to yield higher emissions than spreader stoker boilers as they do when firing coal alone.[121]

3.2.3.2.2 Fuel quality. RDF has a relatively uniform fuel quality. The only major variations result from the type of RDF produced. The major RDF fuel types are:

- Fluff from a wet pulping process,
- Fluff from dry processing-size reduction and air classification,
- Screened fluff from dry processing-size reduction, air classification, and screening,
- d-RDF (densified RDF)-pelletization of fluff or screened fluff, and
- Powdered RDF-proprietary commercial process, fuel characterized as a fine dustlike material.[122]

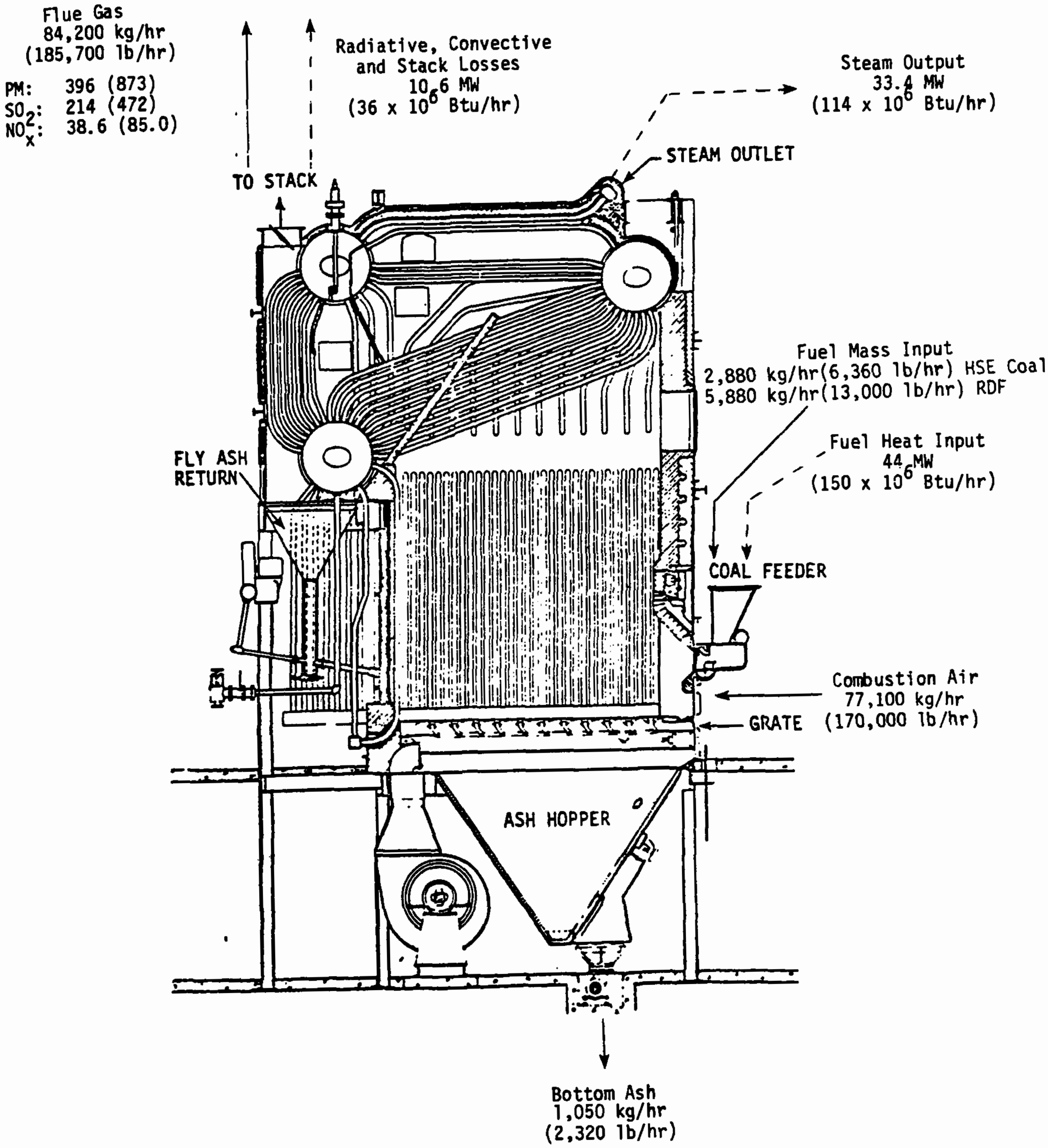

Figure 3-12. Energy and Material Balances for a Representive RDF/Coal Cofired Spreader Stoker Boiler.[115]

(Courtesy of Babcock & Wilcox)

TABLE 3-15. BASES AND ASSUMPTIONS FOR RDF/COAL COFIRED BOILER[116]

Basis/Assumption	Value Used
Boiler Bottom Ash	Difference of total ash input and the PM mass emission rate
Excess Air	50%
Boiler Efficiency	76%
Uncontrolled PM Emissions[a]	5.82 lb/10^6 Btu - same as 100% HSE coal firing[a]
SO_2 Emissions[a]	weighted average of emissions from firing coal alone and RDF alone - emissions from firing RDF are based on 100% conversion of sulfur in the fuel
NO_x Emissions[a]	90% of rate for 100% coal firing

[a]Uncontrolled PM emissions were set at the same rate as emissions from coal fired boilers. This was based on limited test data which show no clear trend in uncontrolled PM emissions for boilers co-firing RDF and coal as compared to 100 percent coal firing. Complete conversion of RDF sulfur to SO_2 was assumed so as to provide an estimate of the maximum SO_2 emission rate. The NO_x emission rate was set based on emission data from an operating facility. Emissions from 100 percent coal firing were taken from Fossil Fuel Fired Boilers - Background Information for Proposed Standards and were based on AP-42 emission factors. More details about all of the bases in this table are provided in Reference 116.

TABLE 3-16. RDF AND COAL ANALYSES SELECTED FOR THE REPRESENTATIVE BOILER[117,118]

Material	High Sulfur Eastern Coal Percentage (as fired)	RDF Percentage (as fired)
Carbon	64.80	31.30
Hydrogen	4.43	4.62
Oxygen	6.56	21.44
Nitrogen	1.30	0.61
Sulfur	3.54	0.17
Water	8.79	22.42
Ash	10.58	19.44
Total	100.00	100.00
Higher Heating Value kJ/kg (Btu/lb)	27,440 (11,800)	13,460 (5,790)

TABLE 3-17. UNCONTROLLED EMISSIONS FROM REPRESENTATIVE COAL/RDF-FIRED AND COAL-FIRED SPREADER STOKER BOILERS[119]

Fuel[a]	Capacity (thermal input)	Pollutant	Emissions: Mass kg/hr (lb/hr)	Emissions: Concentration[b] g/Nm^3 (gr/dscf)	Emissions: Heat Input ng/J (lb/10^6 Btu)
50% HSE/ 50% RDF	44 MW (150×10^6 Btu/hr)	PM	396 (873)	6.43 (2.81)	2500 (5.82)
		SO_2	214 (472)	1300[c]	1350 (3.15)
		NO_x	38.6 (85.0)	327[c]	245 (0.567)
100% HSE	44 MW (150×10^6 Btu/hr)	PM	396 (873)	6.80 (2.79)	2500 (5.82)
		SO_2	388 (855)	2350[c]	2450 (5.70)
		NO_x	42.9 (94.5)	364[c]	271 (0.630)

[a]Thermal input basis.

[b]Corrected to 12 percent CO_2.

[c]Gaseous emissions are in parts per million (ppm).

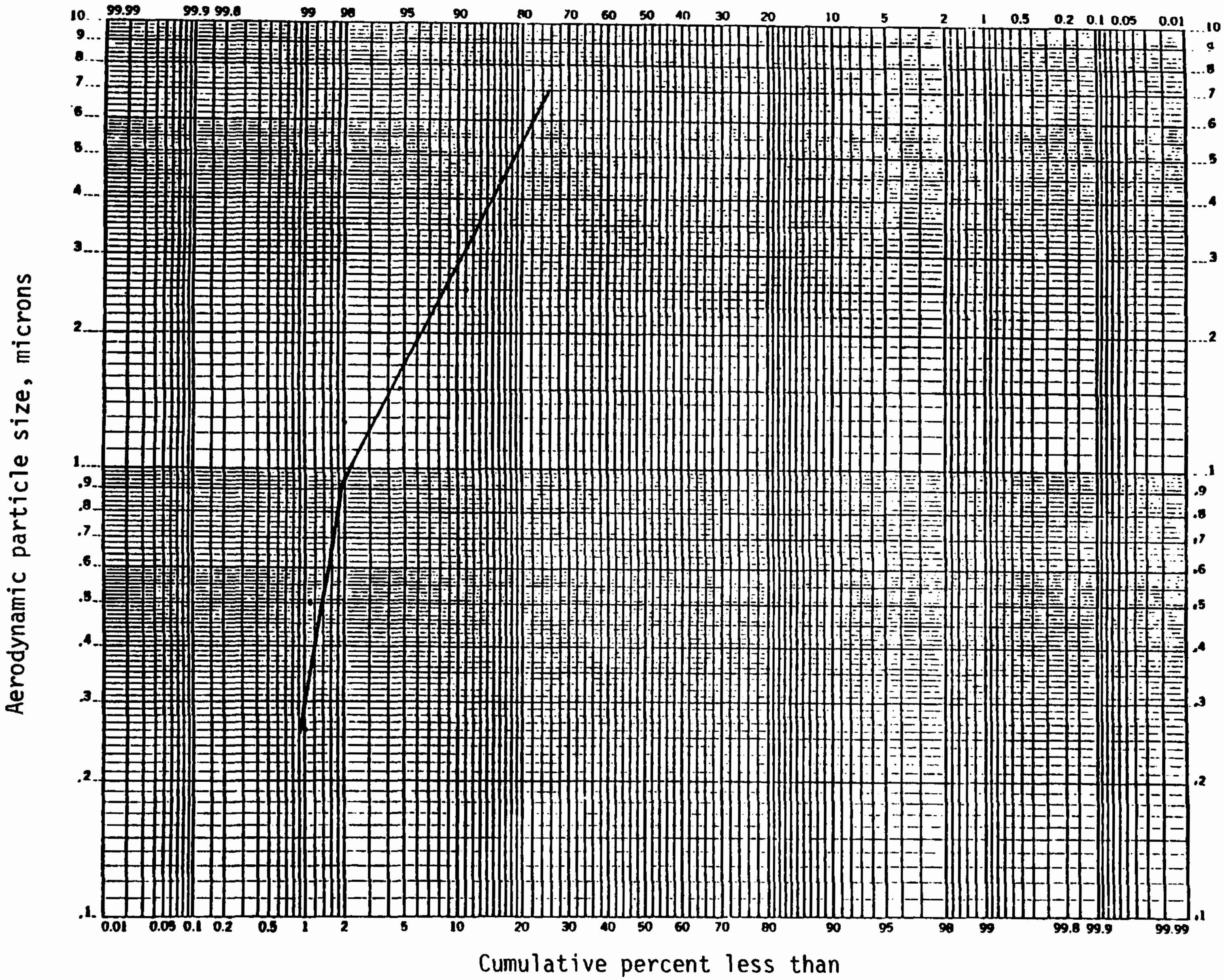

Figure 3-13. Size distribution of uncontrolled PM emissions from a suspension (pulverized coal) RDF/Coal-fired boiler burning 18 percent RDF (heat input basis).[120]

Fluff is a term used to describe the light combustible fraction of raw MSW. The combustion properties of RDF depend upon the degree of processing for the materials described above. Some properties of interest are given in Table 3-18. Choice of the most appropriate type of RDF depends on the type of boiler used. Therefore fuel characteristics which affect emission rates, such as size distribution and moisture content, relate directly back to boiler design. For example, powdered RDF would be combusted in a boiler normally employed for pulverized coal combustion, such as a tangential suspension-fired type. Densified RDF is physically similar to stoker coal and would be combusted in a stoker furnace.[124]

3.2.3.2.3 Boiler operation. The operation factors for RDF/coal boilers that affect uncontrolled emissions are similar to those affecting any coal-fired unit. These are boiler load and boiler excess air. An additional factor affecting emissions for the RDF/coal units is the ratio of RDF to coal. Because of the higher ash content of the RDF (see Table 3-16) uncontrolled PM emissions would be expected to increase. However, no clear trends in uncontrolled PM emission rates have been measured in the present applications of boilers cofiring RDF and coal as compared to 100 percent coal firing.[125] SO_2 and NO_x emissions tend to decrease with increasing RDF (see Table 3-17).[126]

Boilers designed to burn 100 percent RDF are similar to standard coal fired boilers. Although there are insufficient data to quantitatively characterize emissions from these boilers, in general, uncontrolled PM emissions would be expected to be higher than those from coal-fired boilers of equal capacity because of the higher ash content of the RDF (see Table 3-16). SO_2 emissions should be lower due to the lower sulfur content of RDF compared to coal. NO_x emissions would also be expected to decrease compared to coal firing based on the limited, available test data.[127]

3.3 EXISTING STATE AND FEDERAL EMISSIONS REGULATIONS FOR NFFBs

This section presents the existing State and Federal emissions regulations which are applicable to NFFBs. These regulations are used to calculate the "average" State and Federal emissions regulation which would

TABLE 3-18. TYPICAL CHARACTERISTICS OF REFUSE DERIVED FUELS[123]

As-received refuse derived fuel[a]	Density, kg/m^3	(lb/ft^3)	As-received heating value, kJ/kg	(Btu/lb)	H_2O %	Ash %	Approximate particle size
Fluff-wp	224	(14)[b]	8140	(3500)	50	20	2.5 cm (1.0 in)
Fluff-dp	80-144	(5-9)	12,090	(5200)	25	19	2.5-5.7 cm (1.0-2.5 in)
Screened fluff	16-80	(1-5)	16,750	(7200)	16	10	2.5-5.1 cm (1.0-2.0 in)
d-RDF pellets (from fluff)	380-720	(24-45)	12,090	(5200)	15	18	1.3 cm dia. x 2.5 cm long (0.5 in dia. x 1.0 in long)
d-RDF briquettes (from fluff)	750-900	(47-56)[b]	12,090	(5200)	14	18	3.0 x 3.0 x 7.5 cm (1.25 x 1.25 x 3.0 in)
Powdered RDF	480	(30)	18,011	(7750)	2	10	0.15 mm (0.006 in)

[a]Fluff is the term used for the light combustible fraction of the raw MSW.
wp = wet processed: water is used to separate the light combustible fraction from the heavier noncombustibles.
dp = dry processed: air is used to separate the combustible and noncombustible fraction
d-RDF = densified refuse derived fuel.

[b]Estimated.

be applied to a new NFFB if no NSPS were developed. The discussion is presented in two parts. First, a discussion of existing emissions regulations for new NFFBs is presented. Second, the average State or Federal emissions regulation calculation procedure is described and calculated average levels presented along with uncontrolled PM emission rates.

3.3.1 Existing Standards for New Nonfossil Fuel Fired Boilers

Existing Federal and State emission standards applicable to NFFBs were obtained through review of the Environmental Reporter and from telephone conversations with several state agencies. The existing Federal new source performance standards for incinerators (40 CFR 60 Subpart E) were identified as applicable to boilers firing MSW and larger than 45 Mg/day (50 tons/day) charging capacity. State emission standards for boilers and incinerators are often ambiguous with respect to regulation of NFFBs. However, applicable emission standards which specify NFFBs are readily apparent in the regulations of 10 of the 50 states. In the regulations of 34 additional states, comparisons of fuel-burning equipment and fuel definitions reveal emission standards that are applicable to NFFBs. The following three subsections summarize the applicable new source emission standards for wood, bagasse, and GSW-fired boilers.

3.3.1.1 Wood-Fired Boilers. Wood-fired boilers are regulated as a separate category of new source emissions in only seven of the 50 states: Alabama, Arizona, North Carolina, Oklahoma, South Dakota, Tennessee, and Vermont. However, an additional 36 states regulate new source emissions from wood-fired boilers under new source standards such as "particulate matter", "fuel-burning equipment", and "indirect heating equipment" standards. "Fuel-burning equipment" regulations are applicable to wood-fired boilers in 23 states. Applicability is established by defining "fuel" to include wood, bark, and wood waste. "Particulate matter" regulations are general in nature and were used in cases where no other state regulations would apply. Consequently, new source emission standards were found in a total of 43 states.

New source emission standards were not found for wood-fired boilers in the remaining seven states. However these states do not have significant wood boiler capacity and are, therefore, not included in the calculation of baseline emission levels. State regulations concerning PM emissions from wood-fired boilers are presented in Table 3-19.

3.3.1.2 Bagasse-Fired Boilers. Bagasse is burned as a boiler fuel in Florida, Hawaii, Louisiana, Puerto Rico, and Texas. Hawaii regulates bagasse boilers specifically while the other states regulate bagasse boilers under fuel-burning equipment or mass emission limitation regulations. These regulations were used to calculate the average of existing emission regulations for bagasse-fired boilers. State regulations concerning PM emissions from bagasse-fired boilers are presented in Table 3-20.

3.3.1.3 General Solid Waste-Fired Boilers. Although GSW boilers are not specifically regulated in any state, new source emission standards applicable to GSW-fired boilers were identified in 45 of the 50 states. In 10 of the 45 states, GSW boilers are regulated as incinerators, while 25 states classify GSW boilers under "fuel-burning equipment" regulations. Many states have new incinerator regulations that apply to GSW boilers. However, many specify "fuel-burning equipment" regulations as being applicable to boilers and incinerators that burn GSW for the purpose of producing steam. The remaining 10 states were found to regulate GSW boilers under general "particulate matter" and "indirect heat exchanger" regulations. State regulations concerning PM emissions from GSW-fired boilers are presented in Table 3-21. GSW boilers firing municipal type solid waste and larger than 45 Mg/day (50 tons/day) charging capacity are also regulated by 40 CFR 60 Subpart E. The applicable emission limit for these boilers is 0.18 g/dNm^3 (0.08 gr/dscf) corrected to 12 percent CO_2.

3.3.2 Calculation of the Average of Existing Emissions Regulations

Currently, Federal new source performance standards apply to MSW-fired boilers with over 45 Mg/day (50 tons/day) capacity, but they do not apply to other boilers fired with 100 percent nonfossil fuels. However, state emission limits do apply to new NFFB installations. Therefore, the average of existing emissions regulations is selected as the applicable Federal

TABLE 3-19. STATE REGULATIONS FOR PARTICULATE MATTER (PM) EMISSIONS FROM NEW WOOD-FIRED BOILERS.[128,129]

State	How Regulated	Basis for Limit		Applicability
Alabama	wood waste boilers	0.20 gr/dscf @50% excess air	(0.46 g/dNm^3)	wood only
Alaska	fuel-burning equipment	0.15 gr/scf	(0.34 g/Nm^3)	wood waste
Arizona	wood waste burner	0.20 gr/dscf @12 CO_2	(0.46 g/Nm^3)	wood and wood waste
California	any boiler	0.10 gr/dscf @12% CO_2	(0.23 g/dNm^3)	steam generation
Connecticut	fuel-burning equipment	0.11 lb/10^6 BTU	(47.3 ng/J)	steam generation
Florida	fuel-burning equipment	0.30 lb/10^6 BTU	(129 ng/J)	Q <30 x 10^6 BTU/hr (31.7 GJ/hr)
		0.20 lb/10^6 BTU	(85.0 ng/J)	Q $\geq$ 30 x 10^6 BTU/hr (31.7 GJ/hr)
Georgia	fuel-burning equipment	0.50 lb/10^6 BTU	(215 ng/J)	Q $\leq$ 10 x 10^6 BTU/hr (10.6 GJ/hr)
		$E=0.5(\frac{10}{Q})^{0.5}$ lb/10^6 BTU	($698.3(\frac{10}{Q})^{0.5}$ ng/J)	Q $\geq$ 10 x 10^6 BTU/hr (10.6 GJ/hr)
				Q $\leq$ 250 x 10^6 BTU/hr (263.8 GJ/hr)
		0.10 lb/10^6 BTU	(43.0 ng/J)	Q >250 x 10^6 BTU/hr (263.8 GJ/hr)
Idaho	fuel-burning equipment	0.08 gr/dscf	(0.18 g/dNm^3)	wood products
Illinois	fuel-burning equipment	0.11 lb/10^6 BTU	(47.3 ng/J)	any new solid fuel burner
Indiana	fuel-combustion steam generators	0.60 lb/10^6 BTU	(258 ng/J)	Q <25 x 10^6 BTU/hr (26.4 GJ/hr)
		0.35 lb/10^6 BTU	(151 ng/J)	Q $\geq$ 25 x 10^6 BTU/hr (26.4 GJ/hr)
				Q $\leq$ 250 x 10^6 BTU/hr (263.8 GJ/hr)
		0.10 lb/10^6 BTU	(43.0 ng/J)	Q >250 x 10^6 BTU/hr (263.8 GJ/hr)

See footnotes at end of table.

TABLE 3-19. (CONTINUED)

State	How Regulated	Basis for Limit		Applicability
Iowa	indirect heating equipment	0.60 $lb/10^6$ BTU	(258 ng/J)	Q <4000 x 10^6 BTU/hr (4200 GJ/hr)
Kansas	indirect heating equipment	0.60 $lb/10^6$ BTU	(258 ng/J)	Q <10 x 10^6 BTU/hr (10.6 GJ/hr)
		$E=1.026\ Q^{-0.233} lb/10^6$ BTU	$(446.7\ Q^{-0.233} ng/J)$	Q $\geq$ 10 x 10^6 BUT/hr (10.6 GJ/hr)
				Q <10,000 x 10^6 BTU/hr (10,550 GJ/hr)
		0.12 $lb/10^6$ BTU	(51.6 ng/J)	Q $\geq$ 10,000 x 10^6 BTU/hr (10,550 GJ/hr)
Kentucky	indirect heating equipment	0.56 $lb/10^6$ BTU	(241 ng/J)	Q $\leq$ 10 x 10^6 BTU/hr (10.6 GJ/hr)
		$E=0.9644\ Q^{-0.2356} lb/10^6$ BTU	$(420.0\ Q^{-0.2356} ng/J)$	Q >10 x 10^6 BTU/hr (10.6 GJ/hr)
				Q $\leq$ 250 x 10^6 BTU/hr (263.8 GJ/hr)
		0.10 $lb/10^6$ BTU	(43.0 ng/J)	Q >250 x 10^6 BTU/hr (263.8 GJ/hr)
Louisiana	fuel-burning equipment	0.60 $lb/10^6$ BTU	(258 ng/J)	all fuels
Maine	fuel-burning equipment	0.60 $lb/10^6$ BTU	(258 ng/J)	Q $\leq$ 10 x 10^6 BTU/hr (10.6 GJ/hr)
		$E=1.08\ Q^{-0.256} lb/10^6$ BTU	$(470.8\ Q^{-0.256} ng/J)$	Q >10 x 10^6 BTU/hr (10.6 GJ/hr)
				Q $\leq$ 150 x 10^6 BTU/hr (158 GJ/hr)
		0.30 $lb/10^6$ BTU	(129 ng/J)	Q >150 x 10^6 BTU/hr (158 GJ/hr)
Massachusetts	fuel-burning equipment	0.10 $lb/10^6$ BTU	(43.0 ng/J)	Q >3 x 10^6 BTU/hr (3.2 GJ/hr)
Michigan	fuel-burning equipment	0.50 lb/1000 lb @50% Excess air	(0.50 g/kg)	Wood fuel 75% of total input

See footnotes at end of table

TABLE 3-19. (CONTINUED)

State	How Regulated	Basis for Limit		Applicability
Minnesota	fossil fuel-burning direct heating equipment	0.10 gr/scf	(0.23 g/Nm^3)	flue gas flow $<$7000 scfm (3.304 Nm^3/s)
		0.089 gr/scf	(0.200 g/Nm^3)	flue gas flow $\leq$ 10,000 scfm (4.720 Nm^3/s)
		0.057 gr/scf	(0.130 g/Nm^3)	flue gas flow $\leq$ 40,000 scfm (18.878 Nm^3/s)
		0.05 gr/scf	(0.11 g/Nm^3)	flue gas flow $\leq$ 60,000 scfm (28.317 Nm^3/s)
		0.021 gr/scf	(0.010 g/Nm^3)	flue gas flow $\leq$ 8,000,000 scfm (3775.600 Nm^3/)
Mississippi	fuel-burning equipment	0.30 gr/dscf	(0.69 g/dNm^3)	spent wood
Missouri	fuel-burning equipment	0.40 lb/10^6 BTU	(172 ng/J)	Q $\leq$ 10 x 10^6 BTU/hr (10.6 GJ/hr)
		$E=0.8\ Q^{-0.301}$ lb/10^6 BTU	(349.6 $Q^{-0.301}$ ng/J)	Q $>$10 x 10^6 BTU/hr (10.6 GJ/hr)
Montana	fuel-burning equipment	0.60 lb/10^6 BTU	(258 ng/J)	Q $\leq$ 10 x 10^6 BTU/hr (10.6 GJ/hr)
		0.35 lb/10^6 BTU	(151 ng/J)	Q $>$10 x 10^6 BTU/hr (10.6 GJ/hr)
				Q $\leq$ 100 x 10^6 BTU/hr (106 GJ/hr)
		0.28 lb/10^6 BTU	(120 ng/J)	Q $>$100 x 10^6 BTU/hr (106 GJ/hr)
				Q $\leq$ 1000 x 10^6 BTU/hr (1055 GJ/hr)
Nebraska	fuel-burning equipment	0.60 lb/10^6 BTU	(258 ng/J)	Q $\leq$ 10 x 10^6 BTU/hr (10.6 GJ/hr)
		$E=1.026\ Q^{-0.233}$ lb/10^6 BTU	(446.7 $Q^{-0.233}$ ng/J)	Q $>$10 x 10^6 BTU/hr (10.6 GJ/hr)
				Q $\leq$ 3800 x 10^6 BTU/hr (4009 GJ/hr)
		0.15 lb/10^6 BTU	(65.0 ng/J)	Q $>$3800 x 10^6 BTU/hr (4009 GJ/hr)
Nevada	indirect heat transfer	$E=1.02\ Q^{-0.231}$ lb/10^6 BTU	(444.0 $Q^{-0.231}$ ng/J)	Q $\geq$ 10 x 10^6 BTU/hr (10.6 GJ/hr)
				Q $<$ 4000 x 10^6 BTU/hr (4220 GJ/hr)
		$E=17.0\ Q^{-0.568}$ lb/10^6 BTU	(7534.9 $Q^{-0.569}$ ng/J)	Q $\geq$4000 x 10^6 BTU/hr (4220 GJ/hr)

See footnotes at end of table

TABLE 3-19. (CONTINUED)

State	How Regulated	Basis for Limit		Applicability
New Hampshire	fuel-burning equipment	0.60 $lb/10^6$ BTU	(258 ng/J)	$Q \leq 10 \times 10^6$ BTU/hr (10.6 GJ/hr)
		0.40 $lb/10^6$ BTU	(172 ng/J)	$Q > 10 \times 10^6$ BTU/hr (10.6 GJ/hr)
				$Q \leq 50 \times 10^6$ BTU/hr (52.8 GJ/hr)
		0.35 $lb/10^6$ BTU	(151 ng/J)	$Q > 50 \times 10^6$ BTU/hr (52.8 GJ/hr)
				$Q \leq 100 \times 10^6$ BTU/hr (106 GJ/hr)
		0.10 $lb/10^6$ BTU	(43.0 ng/J)	$Q > 100 \times 10^6$ BTU/hr (106 GJ/hr)
New York	stationary combustion installations	0.60 $lb/10^6$ BTU	(258 ng/J)	$Q > 1 \times 10^6$ BTU/hr (1.1 GJ/hr)
				$Q \leq 10 \times 10^6$ BTU/hr (10.6 GJ/hr)
		$E=1.0\ Q^{-0.22} lb/10^6$ BTU	($435.0\ Q^{-0.22}$ ng/J)	$Q > 10 \times 10^6$ BTU/hr (10.6 GJ/hr)
				$Q \leq 10{,}000 \times 10^6$ BTU/hr (10,550 GJ/hr)
North Carolina	wood burning indirect heat exhangers	0.70 $lb/10^6$ BTU	(301 ng/J)	$Q \leq 10 \times 10^6$ BTU/hr (10.6 GJ/hr)
		$E=1.1698\ Q^{-0.223} lb/10^6$ BTU	($509.0\ Q^{-0.223}$ ng/J)	$Q > 10 \times 10^6$ BTU/hr (10.6 GJ/hr)
North Dakota	fuel-burning equipment used for indirect heating	$E=0.811\ Q^{-0.131} lb/10^6$BTU	($351.1\ Q^{-0.131}$ ng/J)	Wood
Ohio	fuel-burning equipment	0.40 $lb/10^6$ BTU	(172 ng/J)	$Q \leq 10 \times 10^6$ BTU/hr (10.6 GJ/hr)
		$E=0.80\ Q^{-0.301} lb/10^6$BTU	($349\ Q^{-0.301}$ ng/J)	$Q > 10 \times 10^6$ BTU/hr (10.6 GJ/hr)
				$Q \leq 1000 \times 10^6$ BTU/hr (1055 GJ/hr)
		0.10 $lb/10^6$ BTU	(43.0 ng/J)	$Q > 1000 \times 10^6$ BTU/hr (1055 GJ/hr)

See footnotes at end of table

TABLE 3-19. (CONTINUED)

State	How Regulated	Basis for Limit		Applicability
Oklahoma	wood waste burning equipment	0.60 lb/10^6 BTU	(258 ng/J)	Q $\leq$ 10 x 10^6 BTU/hr (10.6 GJ/hr)
		0.35 lb/10^6 BTU	(151 ng/J)	Q >10 x 10^6 BTU/hr (10.6 GJ/hr)
				Q $\leq$ 100 x 10^6 BTU/hr (106 GJ/hr)
		0.20 lb/10^6 BTU	(86.0 ng/J)	Q >100 x 10^6 BTU/hr (106 GJ/hr)
				Q $\leq$ 1000 x 10^6 BTU/hr (1055 GJ/hr)
		0.10 lb/10^6 BTU	(43.0 ng/J)	Q >1000 x 10^6 BTU/hr (1055 GJ/hr)
				Q $\leq$ 10,000 x 10^6 BTU/hr (10,550 GJ/hr)
Oregon	fuel-burning equipment	0.10 gr/dscf	(0.23 g/dNm^3)	all fuel burning equipment
Pennsylvania	combustion units	0.40 lb/10^6 BTU	(172 ng/J)	Q $\leq$ 50 x 10^6 BTU/hr (52.8 GJ/hr)
		E=3.6 $Q^{-0.56}$lb/10^6BTU	(1595 $Q^{-0.56}$ng/J)	Q >50 x 10^6 BTU/hr (52.8 GJ/hr)
				Q $\leq$ 600 x 10^6 BTU/hr (633 GJ/hr)
		0.10 lb/10^6 BTU	(43.0 ng/J)	Q >600 x 10^6 BTU/hr (633 GJ/hr)
Puerto Rico	fuel-burning equipment	0.30 lb/10^6 BTU	(129 ng/J)	solid fuel
Rhode Island	fossil fuel-burning equipment	0.20 lb/10^6 BTU	(86.0 ng/J)	Q $\leq$ 250 x 10^6 BTU/hr (264 GJ/hr)
		0.10 lb/10^6 BTU	(43.0 ng/J)	Q >250 x 10^6 BTU/hr (264 GJ/hr)
South Carolina	fuel-burning operations	0.60 lb/10^6 BTU	(258 ng/J)	Q <1300 x 10^6 BTU/hr (1372 GJ/hr)
		E=57.84 $Q^{-0.637}$lb/10^6 BTU	(25731 $Q^{-0.637}$ng/J)	Q $\geq$ 1300 x 10^6 BTU/hr (1372 GJ/hr)
South Dakota	wood burners	0.30 lb/10^6 BTU	(129 ng/J)	solid fuel

See footnotes at end of table

TABLE 3-19. (CONTINUED)

State	How Regulated	Basis for Limit		Applicability
Tennessee	wood fired fuel-burning equipment	0.330 gr/dscf @12% CO_2	(0.760 g/dNm^3)	$Q \leq 25 \times 10^6$ BTU/hr (26.4 GJ/hr)
		E=0.00173 Q + .0267 gr/dscf	(-0.00396 Q + .0611 g/dNm^3) @12% CO_2	$Q > 25 \times 10^6$ BTU/hr (26.4 GJ/hr) $Q \leq 100 \times 10^6$ BTU/hr (106 GJ/hr)
		0.20 gr/dscf @12% CO_2	(0.46 g/dNm^3)	$Q > 100 \times 10^6$ BTU/hr (106 GJ/hr)
Texas	particulate emissions	0.10 $lb/10^6$ BTU	(43.0 ng/J)	general applicability
Vermont	wood fuel-burning equipment	0.20 gr/dscf @12% CO_2	(0.46 g/dNm^3)	$Q \leq 3.3 \times 10^6$ BTU/hr (3.5 GJ/hr)
		0.10 gr/dscf @12% CO_2	(0.23 g/dNm^3)	$Q > 3.3 \times 10^6$ BTU/hr (3.5 GJ/hr)
Virginia	fuel-burning equipment	0.60 $lb/10^6$ BTU	(258 ng/J)	$Q \leq 10 \times 10^6$ BTU/hr (10.6 GJ/hr)
		$E=1.0906\ Q^{-0.2594}$ $lb/10^6$ BTU	($475.5\ Q^{-0.2594}$ ng/J)	$Q > 10 \times 10^6$ BTU/hr (10.6 GJ/hr)
Washington	combustion incinerator sources	0.20 gr/dscf	(0.46 g/dNm^3)	wood combustion for steam production
West Virginia	indirect heat exchangers	.05 Q lb/hr	(0.022 Q kg/hr)	$E' \leq 1200$ lb/hr (544.3 kg/hr)
Wisconsin	fuel-burning installations	0.50 $lb/10^6$ BTU	(215 ng/J)	$Q \leq 100 \times 10^6$ BTU/hr (106 GJ/hr)
		0.15 $lb/10^6$ BTU	(65.0 ng/J)	$Q > 100 \times 10^6$ BTU/hr (106 GJ/hr) $Q \leq 250 \times 10^6$ BTU/hr (264 GJ/hr)
		0.10 $lb/10^6$ BTU	(43.0 ng/J)	$Q > 250 \times 10^6$ BTU/hr (264 GJ/hr)
Wyoming	fuel-burning equipment	0.10 $lb/10^6$ BTU	(43.0 ng/J)	wood fuel

Q = design heat input, 10^6 BTU/hr (GJ/hr)   E = emission rate, $lb/10^6$ BTU (ng/J)   F = fuel input, lb/hr (kg/hr)

E' = emission rate, lb/hr (kg/hr)

TABLE 3-20. STATE REGULATIONS FOR PARTICULATE MATTER (PM) EMISSIONS FROM NEW BAGASSE-FIRED BOILERS.[128,129]

State	How Regulated	Basis for Limit	Applicability
Florida	carbonaceous fuel-burning	0.30 lb/10^6 BTU (129 ng/J)	Q < 30 x 10^6 BTU/hr (31.7 GJ/hr)
		0.20 lb/10^6 BTU (86 ng/J)	Q $\geq$ 30 x 10^6 BTU/hr (31.7 GJ/hr)
Hawaii	bagasse boilers	0.40 lb/100 lb bagasse (0.40 kg/100 kg)	bagasse only
Louisiana	fuel-burning equipment	0.60 lb/10^6 BTU (258 ng/J)	all fuels
Puerto Rico	fuel-burning equipment	0.30 lb/10^6 BTU (129 ng/J)	solid fuels
Texas	particulate matter emissions	0.10 lb/10^6 BTU (43 ng/J)	general applicability

Q = boiler heat input, 10^6 BTU/hr (GJ/hr)

TABLE 3-21. STATE REGULATIONS FOR PARTICULATE MATTER (PM) EMISSIONS FROM NEW GENERAL SOLID WASTE-FIRED BOILERS[128,129]

State	How Regulated	Basis for Limit	Applicability
Alabama	fuel-burning equipment	0.50 $lb/10^6$ BTU (215 ng/J)	$Q=10 \times 10^6$ BTU/hr (10.6 GJ/hr)
		0.15 $lb/10^6$ BTU (64.5 ng/J)	$Q=150 \times 10^6$ BTU/hr (158 GJ/hr)
		0.12 $lb/10^6$ BTU (51.6 ng/J)	$Q=400 \times 10^6$ BTU/hr (422 GJ/hr)
Alaska	fuel-burning equipment	0.10 gr/scf (0.23 g/Nm^3)	municipal waste
Arizona	fuel-burning equipment	$M=1.02\ Q^{0.760}$ lb/hr ($0.44\ Q^{0.760}$ kg/hr)	$Q \leq 4200 \times 10^6$ BTU/hr (4431 GJ/hr)
		$M=17.0\ Q^{0.432}$ lb/hr ($7.31\ Q^{0.432}$ kg/hr)	$Q > 4200 \times 10^6$ Btu/hr (4431 GJ/hr)
Arkansas	PM emissions	0.20 gr/dscf (0.45 g/dNm^3) @12% CO	incinerators
Colorado	fuel-burning equipment	$E=0.50\ Q^{-0.26}$ $lb/10^6$ BTU ($218.0\ Q^{-0.26}$ ng/J)	$Q > 1.0 \times 10^6$ BTU/hr (1.1 GJ/hr)
			$Q \leq 500 \times 10^6$ BTU/hr (528 GJ/hr)
Connecticut	fuel-burning equipment	0.10 $lb/10^6$ BTU (43.0 ng/J)	all fuels
Delaware	fuel-burning equipment	0.30 $lb/10^6$ BTU (129 ng/J)	$Q > 1 \times 10^6$ BTU/hr (1.1 GJ/hr)
Florida	carbonaceous fuel-burning equipment	0.30 $lb/10^6$ BTU (129 ng/J)	$Q < 30 \times 10^6$ BTU/hr (31.7 GJ/hr)
		0.20 $lb/10^6$ BTU (86.0 ng/J)	$Q \geq 30 \times 10^6$ BTU/hr (31.7 GJ/hr)
Georgia	fuel-burning equipment	0.50 $lb/10^6$ BTU (215 ng/J)	$Q < 10 \times 10^6$ BTU/hr (10.6 GJ/hr)
		$E=0.50\ (10/Q)^{0.5}$ $lb/10^6$ BTU ($698.3\ (10/Q)^{0.5}$ ng/J)	$Q \geq 10 \times 10^6$ BTU/hr (10.6 GJ/hr)
			$Q \leq 250 \times 10^6$ BTU/hr (264 GJ/hr)
		0.10 $lb/10^6$ BTU (43.0 ng/J)	$Q > 250 \times 10^6$ BTU/hr (264 GJ/hr)

See footnotes at end of table

TABLE 3-21. (CONTINUED)

State	How Regulated	Basis for Limit	Applicability
Hawaii	fuel-burning equipment	0.40 lb/100 lb (0.40 kg/100 kg)	refuse
Idaho	fuel-burning equipment	0.08 gr/dscf (0.18 g/gNm^3) @8% O_2	Q $\geq$ 10 x 10^6 BTU/hr (10.6 GJ/hr)
Illinois	fuel-burning equipment	0.10 lb/10^6 BTU (43.0 ng/J)	solid-fuel combustion
Indiana	fuel combustion steam generators	0.60 lb/10^6 BTU (258 ng/J)	Q <25 x 10^6 BTU/hr (26.4 GJ/hr)
		0.35 lb/10^6 BTU (151 ng/J)	Q $\geq$ 25 x 10^6 BTU/hr (26.4 GJ/hr)
			Q $\leq$ 250 x 10^6 BTU/hr (264 GJ/hr)
		0.10 lb/10^6 BTU (43.0 ng/J)	Q >250 x 10^6 Btu/hr (264 GJ/hr)
Iowa	combustion from indirect heat exchangers	0.60 lb/10^6 BTU (258 ng/J)	Q <4000 x 10^6 Btu/hr (4220 GJ/hr)
Kentucky	general indirect heat exchangers	0.56 lb/10^6 BTU (241 ng/J)	Q $\leq$ 10 x 10^6 BTU/hr (10.6 GJ/hr)
		E=0.9644 $Q^{-0.236}$ lb/10^6 BTU (419.9 $Q^{-0.236}$ng/J)	Q >10 x 10^6 BTU/hr (10.6 GJ/hr)
			Q $\leq$ 250 x 10^6 BTU/hr (264 GJ/hr)
		0.10 lb/10^6 BTU (43.0 ng/J)	Q >250 x 10^6 BTU/hr (264 GJ/hr)
Louisiana	fuel-burning equipment	0.60 lb/10^6 BTU (258 ng/J)	all fuels
Maine	fuel-burning equipment	0.60 lb/10^6 BTU (258 ng/J)	Q $\leq$ 10 x 10^6 BTU/hr (10.6 GJ/hr)
		E=1.08 $Q^{-0.256}$ lb/10^6 BTU (470.8 $Q^{-0.256}$ ng/J)	Q >10 x 10^6 BTU/hr (10.6 GJ/hr)
			Q $\leq$ 150 x 10^6 BTU/hr (158 GJ/hr)
		0.30 lb/10^6 BTU (129 ng/J)	Q >150 x 10^6 BTU/hr (158 GJ/hr)
Massachusetts	fuel-burning equipment	0.10 lb/10^6 BTU (43.0 ng/J)	Q $\geq$ 3 x 10^6 BTU/hr (3.2 GJ/hr)

See footnotes at end of table

TABLE 3-21. (CONTINUED)

State	How Regulated	Basis for Limit	Applicability
Michigan	incinerators	0.65 lb/1000 lbs gas (0.65 kg/1000 kg gas)	$R \leq 100$ lb/hr (45 kg/hr)
		0.30 lb/1000 lbs gas (0.14 kg/1000 kg gas)	$R > 100$ lb/hr (45 kg/hr)
Minnesota	incinerators	0.20 gr/dscf (0.46 g/dNm^3) @12% CO_2	$R \leq 200$ lb/hr (90.7 kg/hr)
		0.15 gr/dscf (0.34 g/dNm^3) @12% CO_2	$R > 200$ lb/hr (90.7 kg/hr)
			$R \leq 2000$ lb/hr (907 kg/hr)
		0.10 gr/dscf (0.23 g/dNm^3) @12% CO_2	$R > 2000$ lb/hr (907 kg/hr)
			$R \leq 4000$ lb/hr (1814 kg/hr)
		0.08 gr/dscf (0.18 g/dNm^3) @12% CO_2	$R > 4000$ lb/hr (1814 kg/hr)
Mississippi	fuel-burning equipment	0.30 gr/dscf (0.69 g/dNm^3)	waste boilers
Missouri	incinerators	0.40 lb/10^6 BTU (172 ng/J)	$Q < 10 \times 10^6$ BTU/hr (10.6 GJ/hr)
		$E=0.80\ Q^{-0.301}$ lb/10^6 BTU (349.6 $Q^{-0.301}$ ng/J)	$Q \geq 10 \times 10^6$ BTU/hr (10.6 GJ/hr)
Nebraska	fuel-burning equipment	0.60 lb/10^6 BTU (258 ng/J)	$Q \leq 10 \times 10^6$ BTU/hr (10.6 GJ/hr)
		$E=1.026\ Q^{-0.233}$ lb/10^6 BTU (446.7 $Q^{-0.233}$ ng/J)	$Q > 10 \times 10^6$ BTU/hr (10.6 GJ/hr)
			$Q \leq 3800 \times 10^6$ Btu/hr (4009 GJ/hr)
		0.15 lb/10^6 BTU (64.5 ng/J)	$Q > 3800 \times 10^6$ BTU/hr (4009 GJ/hr)
Nevada	indirect heat transfer	$E=1.02\ Q^{-0.231}$ lb/10^6 BTU (444.0 $Q^{-0.231}$ ng/J)	$Q \geq 10 \times 10^6$ BTU/hr (10.6 GJ/hr)
			$Q \leq 4000 \times 10^6$ BTU/hr (4220 GJ/hr)
		$E=17.0\ Q^{-0.568}$ lb/10^6 BTU (7535 $Q^{-0.568}$ ng/J)	$Q > 4000 \times 10^6$ BTU/hr (4220 GJ/hr)

See footnotes at end of table

TABLE 3-21. (CONTINUED)

State	How Regulated	Basis for Limit	Applicability
New Hampshire	fuel-burning equipment	0.60 $lb/10^6$ BTU (258 ng/J)	$Q \leq 10 \times 10^6$ BTU/hr (10.6 GJ/hr)
		0.40 $lb/10^6$ BTU (172 ng/J)	$Q > 10 \times 10^6$ BTU/hr (10.6 GJ/hr)
			$Q \leq 50 \times 10^6$ BTU/hr (52.8 GJ/hr)
		0.35 $lb/10^6$ BTU (151 ng/J)	$Q > 50 \times 10^6$ BTU/hr (52.8 GJ/hr)
			$Q \leq 100 \times 10^6$ BTU/hr (106 GJ/hr)
		0.10 lb/10 BTU (43.0 ng/J)	$Q > 100 \times 10^6$ BTU/hr (106 GJ/hr)
New Jersey	indirect heat exchangers	6.0 lb/hr (2.7 kg/hr)	$Q = 10 \times 10^6$ BTU/hr (10.6 GJ/hr)
		18 lb/hr (8.2 kg/hr)	$Q = 150 \times 10^6$ BTU/hr (158.3 GJ/hr)
		40.0 lb/hr (18.1 kg/hr)	$Q = 400 \times 10^6$ BTU/hr (422 GJ/hr)
New York	incinerators	5.0 lb/hr (2.3 kg/hr)	$Q = 10 \times 10^6$ BTU/hr (10.6 GJ/hr)
		52.0 lb/hr (23.6 kg/hr)	$Q = 150 \times 10^6$ BTU/hr (158.3 GJ/hr)
		110 lb/hr (49.9 kg/hr)	$Q = 400 \times 10^6$ BTU/hr (422 GJ/hr)
North Carolina	refuse burning equipment	0.2 lb/hr (0.1 kg/hr)	$R \leq 100$ lb/hr (45.5 kg/hr)
		$M = 0.002\ R$ lb/hr ($0.0009\ R$ kg/hr)	100 lb/hr (45.4 kg/hr) $< R \leq$ 2000 lb/hr (907.2 kg/hr)
		4.0 lb/hr (1.8 kg/hr)	$R >$ 2000 lb/hr (907.2 kg/hr)
North Dakota	incinerators	$M = 0.00515\ R^{0.90}$ lb/hr ($0.00476\ R^{0.90}$ kg/hr)	$R \leq 1000$ lb/hr (454 kg/hr)
		$M = 0.0252\ R^{0.67}$ lb/hr ($0.0194\ R^{0.67}$ kg/hr)	$R > 1000$ lb/hr (454 kg/hr)

See footnotes at end of table

TABLE 3-21. (CONTINUED)

State	How Regulated	Basis for Limit	Applicability
Ohio	incinerators	0.20 lb/100 lb refuse (0.20 kg/100 kg refuse)	R <100 lb/hr (45.4 kg/hr)
		0.10 lb/100 lb refuse (0.10 kg/100 kg refuse)	R $\geq$ 100 lb/hr (45.4 kg/hr)
Oklahoma	fuel-burning equipment	$E=1.09\ Q^{-0.259}$ lb/10^6 BTU (475.2 $Q^{-0.259}$ ng/J)	all particulate emissions
Oregon	refuse-burning equipment	0.10 gr/dscf (0.23 g/dNm^3) @12% CO_2	R $\leq$ 200 lb/hr (90.7 kg/hr)
		0.30 gr/dscf (0.69 g/dNm^3) @12% CO_2	R >200 lb/hr (90.7 kg/hr)
Pennsylvania	combustion units	0.40 lb/10^6 BTU (172 ng/J)	Q $\leq$ 50 x 10^6 BTU/hr (52.8 GJ/hr)
		$E=3.6\ Q^{-0.56}$ lb/10^6 BTU (1595.0 $Q^{-0.56}$ ng/J)	Q >50 x 10^6 BTU/hr (52.8 GJ/hr)
			Q $\leq$ 600 x 10^6 BTU/hr (633 GJ/hr)
		0.1 lb/10^6 BTU (43 ng/J)	Q >600 x 10^6 BTU/hr (633 GJ/hr)
Puerto Rico	fuel-burning equipment	0.30 lb/10^6 BTU (129 ng/J)	solid fuel
Rhode Island	incinerators	0.16 gr/scf (0.37 g/Nm^3)	R <2000 lb/hr (907 kg/hr)
		0.08 gr/scf (0.18 g/Nm^3)	R $\geq$ 2000 lb/hr (907 kg/hr)
South Carolina	fuel-burning equipment	0.60 lb/10^6 BTU (258 ng/J)	Q <1300 x 10^6 BTU/hr (1372 GJ/hr)
		$E=57.84\ Q^{-0.637}$ lb/10^6 BTU (25731 $Q^{-0.637}$ ng/J)	Q $\geq$ 1300 x 10^6 BTU/hr (1372 GJ/hr)
Sough Dakota	fuel-burning equipment	0.30 lb/10^6 BTU (129 ng/J)	solid fuel
Tennessee	incinerators	0.08 gr/scf (0.18 g/Nm^3)	all new incinerators
Texas	particulate matter emissions	0.10 lb/10^6 BTU (43.0 ng/J)	general regulation
Vermont	fuel-burning equipment	0.20 gr/dscf (0.45 g/dNm^3) @12% CO_2	Q $\geq$ 0.2 x 10^6 BTU/hr (0.2 GJ/hr)
			Q $\leq$ 3.3 x 10^6 BTU/hr (3.5 GJ/hr)
		0.10 gr/dscf (0.23 g/dNm^3) @12% CO_2	Q >3.3 x 10^6 BTU/hr (3.5 GJ/hr)

See footnotes at end of table

TABLE 3-21. (CONTINUED)

State	How Regulated	Basis for Limit	Applicability
Virginia	fuel-burning equipment	0.60 lb/10^6 BTU (258 ng/J)	Q <10 x 10^6 BTU/hr (10.6 GJ/hr)
		E=1.096 $Q^{-0.2594}$ lb/10^6 BTU (531.0 $Q^{-0.2594}$ ng/J)	Q >10 x 10^6 BTU/hr (10.6 GJ/hr)
			Q $\leq$ 10,000 x 10^6 BTU/hr (10550 GJ/hr)
Washington	combustion and incineration sources	0.10 gr/scf (0.23 g/dNm^3)	excludes wood combustion
West Virginia	fuel-burning units	M=0.05 Q lb/hr (0.02 Q kg/hr)	Type A fuel burning units
Wisconsin	fuel-burning installations	E=0.3 - 0.0006 Q lb/10^6 BTU (129 - .2580 Q ng/J)	Q $\leq$ 250 x 10^6 BTU/hr (264 GJ/hr)
		0.15 lb/10^6 BTU (64.5 ng/J)	Q >250 x 10^6 BTU/hr (264 GJ/hr)
Wyoming	incinerators	0.20 lb/100 lb (0.20 kg/100 kg)	all incinerators

Q = actual heat input, 10^6 BTU/hr (GJ/hr) R = refuse burned, lb/hr (kg/hr) V = volumetric flow, acfm (m^3/s)

E = emission rate, lb/10^6 BTU (ng/J) M = emission rate, lb/hr (kg/hr) standard or the weighted average of all the applicable state standards, whichever was lower. Use of a weighted average causes the calculated baseline emission level to represent a typical state emission standard for new NFFBs in the absence of a uniform Federal standard. The average emissions regulations derived from these sources are presented in Table 3-22, along with uncontrolled PM emissions.

The following four subsections describe calculation of the average of existing emission regulations based on typical new NFFB capacities and mass balances discussed in Section 3.2 of this chapter. The average of existing emission regulations for boilers cofiring coal with wood or RDF are assumed to be the same as those for boilers 100 percent fired with coal.

3.3.2.1 Wood-Fired Boilers. Calculation of the average of existing emission regulations for wood-fired boilers consisted of four steps. First, using material balances (based on combustion calculations) developed for selected model boilers, the state emission standards were put on a common basis. The selected boilers ranged in size from 8.8 to 117 MW thermal input ($30\text{-}400 \times 10^6$ Btu/hr). Second, weighting factors for each state were calculated based upon the individual state's existing wood-fired boiler capacity divided by the existing national capacity. Third, the weighted emission limit for each state was calculated as the product of its emission limit for the selected boiler and its weighting factor from step 2. Fourth, the average regulation for the selected new wood-fired boiler was determined from summation of the weighted emission limitations. The results of these calculations are presented in Table 3-22 along with the uncontrolled emissions.

3.3.2.2 Bagasse-Fired Boilers. The average of existing emission regulations level for a representative new 58.6 MW (200×10^6 Btu/hr) thermal input bagasse-fired boiler was calculated using the same procedures as used for wood-fired boilers. However, the weighting factor was based on the bagasse-fired boiler capacity for each state multiplied by the fraction of a year corresponding to the state's sugar cane processing season. The resulting emission level is shown in Table 3-22 along with the uncontrolled emission rate.

TABLE 3-22. AVERAGE OF EXISTING EMISSION REGULATIONS AND UNCONTROLLED EMISSIONS FOR NONFOSSIL FUEL-FIRED BOILERS[130]

Fuel	Representative Boiler MW (10^6 Btu/hr)	Uncontrolled Emissions ng/J (lb/10^6 Btu) PM	Uncontrolled Emissions ng/J (lb/10^6 Btu) SO_2	Average State or Federal Emission Regulations ng/J (lb/10^6Btu) PM	Average State or Federal Emission Regulations ng/J (lb/10^6Btu) SO_2
Wood	8.8 (30)	2090 (4.88)	- -	172 (0.40)	N/A N/A
Wood	22 (75)	2090 (4.88)	- -	159 (0.37)	N/A N/A
Wood	44 (150)	2090 (4.88)	- -	146 (0.34)	N/A N/A
Wood	117 (400)	2090 (4.88)	- -	129 (0.30)	N/A N/A
50% Wood/ 50% HSE	44 (150)	2300 (5.35)	1240 (2.89)	138 (0.32)	1075 (2.5)
50% Wood/ 50% HSE	117 (400)	2300 (5.35)	1240 (2.89)	43.0 (0.10)	516 (1.2)
MSW	2.9 (10)	129 (0.30)	211 (0.492)	146 (0.34)	N/A N/A
MSW	44 (150)	1450 (3.37)	211 (0.492)	73.1 (0.17)	N/A N/A
MSW	117 (400)	1450 (3.37)	211 (0.492)	73.1 (0.17)	N/A N/A
50% RDF/ 50% HSE	44 (150)	2500 (5.82)	1350 (3.14)	138 (0.32)	1075 (2.5)
Bagasse	58.6 (200)	2170 (5.05)	- -	267 (0.62)	N/A N/A

3.3.2.3 General Solid Waste-Fired Boilers. Average emission regulations were calculated for typical boiler sizes of 2.9, 44, and 117 MW thermal input (10, 150, and 400 x 10^6 Btu/hr). For the boiler sizes of 44 and 117 MW thermal input (150 and 400 x 10^6 Btu/hr) the emission rate came from Subpart E of 40 CFR 60. For the boiler size of 2.9 MW (10 x 10^6 Btu/hr) weighting factors, based on each state's population (people not boilers) were calculated by dividing the state population by the total national population. (The present GSW boiler populations are too small to provide a reasonable basis for the baseline emission level calculation.) The average of existing emission regulations was then calculated using the same procedure as was used for wood-fired boilers. The results of these calculations for the three GSW boilers are presented in Table 3-22.

3.3.2.4 Nonfossil Fuel/Coal Cofired Boilers. Average emissions regulation levels for PM and SO_2 were determined for boilers cofiring nonfossil fuels with coal. These levels were assumed to be the same as the levels determined for coal-fired boilers in Fossil Fuel Fired Boilers - Background Information for Proposed Standards. These levels were based on a weighted average of state regulations for boilers with less than 73.3 MW (250 x 10^6 Btu/hr) thermal input capacity and on Subpart D of 40 CFR 60 for larger boilers. This assumption was made since regulations are often not clear concerning the treatment of cofired boilers. The average of existing emission regulations for cofired boilers is presented in Table 3-22.

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4. EMISSION CONTROL TECHNIQUES

This chapter describes the techniques available to control emissions from nonfossil fuel fired boilers (NFFBs). Described in this chapter are emission control techniques for particulate matter (Section 4.1), sulfur dioxide (Sections 4.2 and 4.3), and nitrogen oxides (Section 4.4). Descriptions of each technique include discussions of the technique's basic operation, its development status, and its applicability to nonfossil fuel-fired boilers. Also discussed are factors which affect the performance of the control techniques including design parameters, operating conditions, and fuel quality. Data obtained by approved EPA test methods are presented to substantiate control technique performance. Data describing the performance of the best available emission controls are summarized in a separate section (Section 4.5). Additional information on performance test data is presented in Appendix C.

Control systems discussed in this chapter are those meeting one of the following criteria:

- Currently used on nonfossil fuel fired boilers or large pilot-scale installations;
- Currently applied on fossil fuel fired boilers in the industrial, utility, or foreign sectors.

Table 4-1 shows an approximate distribution of emission controls currently used on nonfossil fuel fired boilers.

4.1 CONTROL TECHNIQUES FOR PARTICULATE MATTER

The control of particulate matter emissions from nonfossil fuel fired boilers can be accomplished by using one or more of the following control methods:

- centrifugal separation
- wet scrubbing
- fabric filtration

TABLE 4-1. APPROXIMATE DISTRIBUTION OF PARTICULATE EMISSION CONTROLS CURRENTLY APPLIED TO NONFOSSIL FUEL FIRED BOILERS.[a,b]

Type of Particulate Matter Control	Percentage of Total for Fuel Type			
	Wood	Bagasse	MSW[e]	RDF[e]
None or No Data	53.8	29.7	62.5	20.0
Centrifugal Collectors[c]	36.8	50.9	-	40.0
Wet Scrubbers[d]	7.2	19.4	-	-
Electrostatic Precipitators[d]	0.4	-	37.5	40.0
Fabric Filters[d]	0.4	-	-	-
Gravel-Bed Filters[d]	0.5	-	-	-
Other[d]	0.9	-	-	-

[a]Distribution is based on National Emissions Data System (NEDS)[1], literature, and phone survey. Boilers cofiring fossil and nonfossil fuels are included.

[b]Sulfur dioxide and nitrogen oxide controls have generally not applied to nonfossil fuel fired boilers.

[c]This includes cyclones, multitube cyclones, and dual mechanical collectors.

[d]In many cases these controls are preceeded by a centrifugal collector used as a precleaner.

[e]MSW = municipal solid waste; RDF = refuse derived fuel.

- electrostatic precipitation
- gravel-bed and electrostatic gravel-bed filtration.

Sections 4.1.1 through 4.1.5 separately discuss each of these control techniques. Section 4.1.6 presents test data substantiating the performance of each control technique as applied to NFFBs.

4.1.1 Centrifugal Separation (Multitube Cyclones)

4.1.1.1 Process Description. Devices using centrifugal separation to remove particulate matter from gas streams are called cyclones or mechanical collectors. At the entrance of the cyclone a spin is imparted to the particle-laden gas. This spin creates a centrifugal force which causes the particulate matter to move away from the axis of rotation and towards the walls of the cyclone. Particles which contact the walls of the cyclone tube are directed to a dust collection hopper where they are deposited.

In a typical single cyclone the gas enters tangentially to initiate the spinning motion. In a multitube cyclone the gas approaches the entrance axially and has the spin imparted by a stationary "spin" vane that is in its path. This allows the use of many small, higher efficiency cyclone tubes, with a common inlet and outlet, in parallel to the gas flow stream. Figure 4.1-1 illustrates the configuration of the individual tube and an assembly of such tubes in a multitube cyclone.

One variation of the multitube cyclone is two similar mechanical collectors placed in series. This system is often referred to as a dual or double mechanical collector. The collection efficiency of the dual mechanical collector is theoretically improved over that of a single mechanical collector.

4.1.1.2 Development Status and Applicability to Nonfossil Fuel Fired Boilers. Fly ash collection by multitube cyclones is a well established technology, and has been used for many years to limit particulate emissions from industrial and utility boilers.[3] Multitube cyclones were the most common device used for fly ash control before stricter emission regulations were enacted. However, where a mechanical collector alone cannot meet applicable emission levels, in many cases they are commonly used as precleaners prior to a more efficient control device.

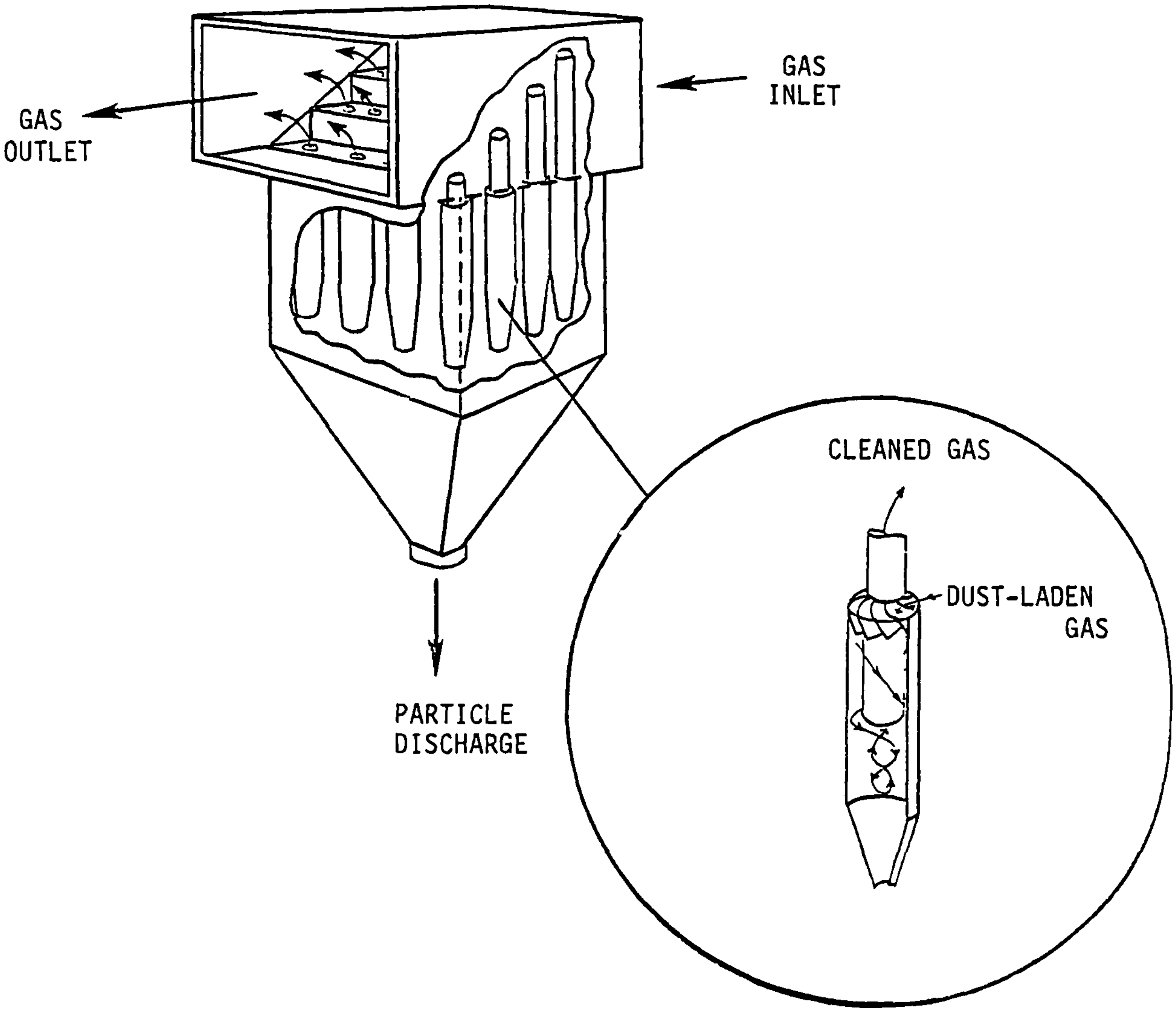


Figure 4.1-1. Schematic of a multiple cyclone and detail of an individual tube.[2]

Multitube cyclones applied to wood-fired boilers are also used to increase overall boiler efficiency. The larger fly ash particles collected by cyclones on wood-fired boilers comprise 20-90% unburned carbon[4] and can be re-injected into the boiler for more complete combustion. Re-injecting the large flyash particles typically increases boiler efficiency by 1-4 percent.[5]

Although multitube cyclones are generally applicable to control particulate matter from any of the NFFBs, their current use is limited to the control of particulate matter from wood and bagasse boilers. Cyclones are rarely used on MSW and RDF boilers as the sole control device or as a precleaner because of their relative ineffectiveness in removing fine particulate matter.

Because of their modular configuration, multitube cyclones are applicable to all sizes of wood- and bagasse-fired boilers. There are several operational factors associated with these boilers that affect mechanical collector performance and limit applicability as the sole PM control device. These and other factors are discussed in the next section.

4.1.1.3. Factors Affecting Performance. The most important design factors affecting performance for a cyclone are the inlet gas velocity, the diameter of the tubes, the number and angle of axial vanes, the construction materials, and the system pressure drop.

Most multitube cyclones are axial-gas entry units designed for gas velocities of 25.4 to 35.6 m/sec (5,000 to 7,000 ft/min) in the entry vane region. Such high velocities require the use of hard alloy materials for the vanes (gray or white iron or chromehard steel) to minimize vane erosion.[6]

However, when cyclones are applied to wood-fired boilers, gas velocities are generally limited to 21.3 m/sec (4,200 ft/min) to prevent the breakup of the particulate into smaller particles.[55] Figure 4.1-2 is a theoretical curve that presents the variation of the collection efficiency resulting from the variation of the inlet gas velocity. As shown in Figure 4.1-2, cyclone collection efficiency usually decreases with reductions in the inlet gas velocity below the design velocity. However,

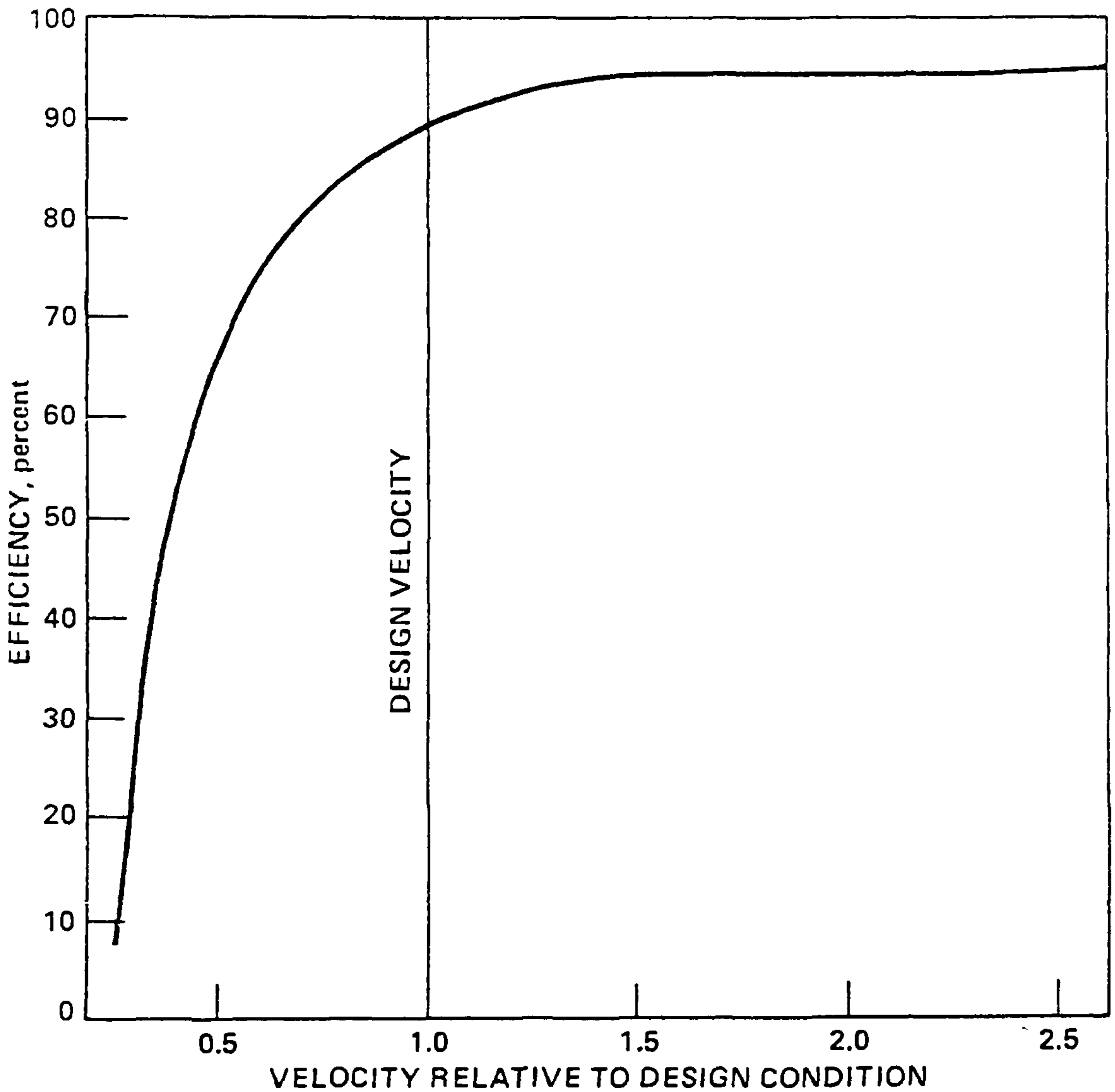


Figure 4.1-2. Variation of a single cyclone collection efficiency with gas velocity.[7]

collection efficiencies may also decrease at high gas velocities due to plugging of the tubes or to break up of the fly ash particles.

The performance of any cyclonic device is primarily a function of the particle size distribution of the particulate matter to be collected. As shown in Figures 4.1-3 and 4.1-4 the collection efficiency of a cyclone increases as the percentage of larger particles increases.

Particle collection efficiency for most cyclonic devices varies inversely with the diameter of the collecting tube. A reduction in tube diameter increases the radial force acting upon the particles so that their transit to the wall region and their removal is accelerated.[6] Figure 4.1-3 illustrates comparative collection efficiencies for two axial-entry cyclones with diameters of 15.2 and 30.5 cm (6 and 12 inches), respectively, as a function of the percent of dust under 10 um. Fractional efficiency data for multitube cyclones of different tube diameters for collecting particulate matter from coal and oil-fired boilers are presented in Figure 4.1-4. The affect of particle size and tube diameter on mechanical collector efficiency for NFFBs should be the same as shown for coal or oil.

Operational procedures related to the boiler/control device system that hamper mechanical collector performance include transient operations such as startup, shutdown, emergency upsets and load variation.[56] In addition, air leakage, cyclone corrosion, particle reentrainment, tube plugging, pressure drop and the degree of fly ash reinjection will affect mechanical collector outlet emissions.[57] Large load swings significantly affect removal efficiency. At constant load and inlet particle size distribution, outlet emissions will be proportional to inlet mass loading. Therefore, a large increase in fly ash loading (which could result from variations in load, fuel ash content, soot blowing or fly ash reinjection) will increase emissions.

Proper mechanical collector maintenance is essential to sustaining the desired removal efficiency. To avoid efficiency losses due to corrosion of the cyclone from acid condensation or particle abrasion, the cyclone should be constructed of materials that will withstand the highest expected loading

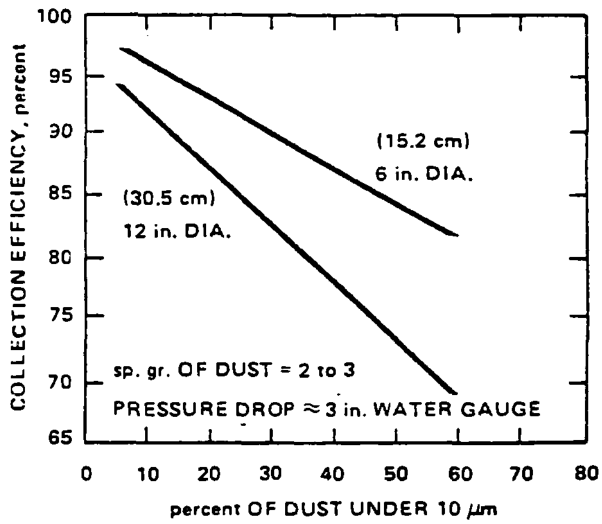


Figure 4.1-3. Typical overall collection efficiency of axial-entry cyclones.[8]

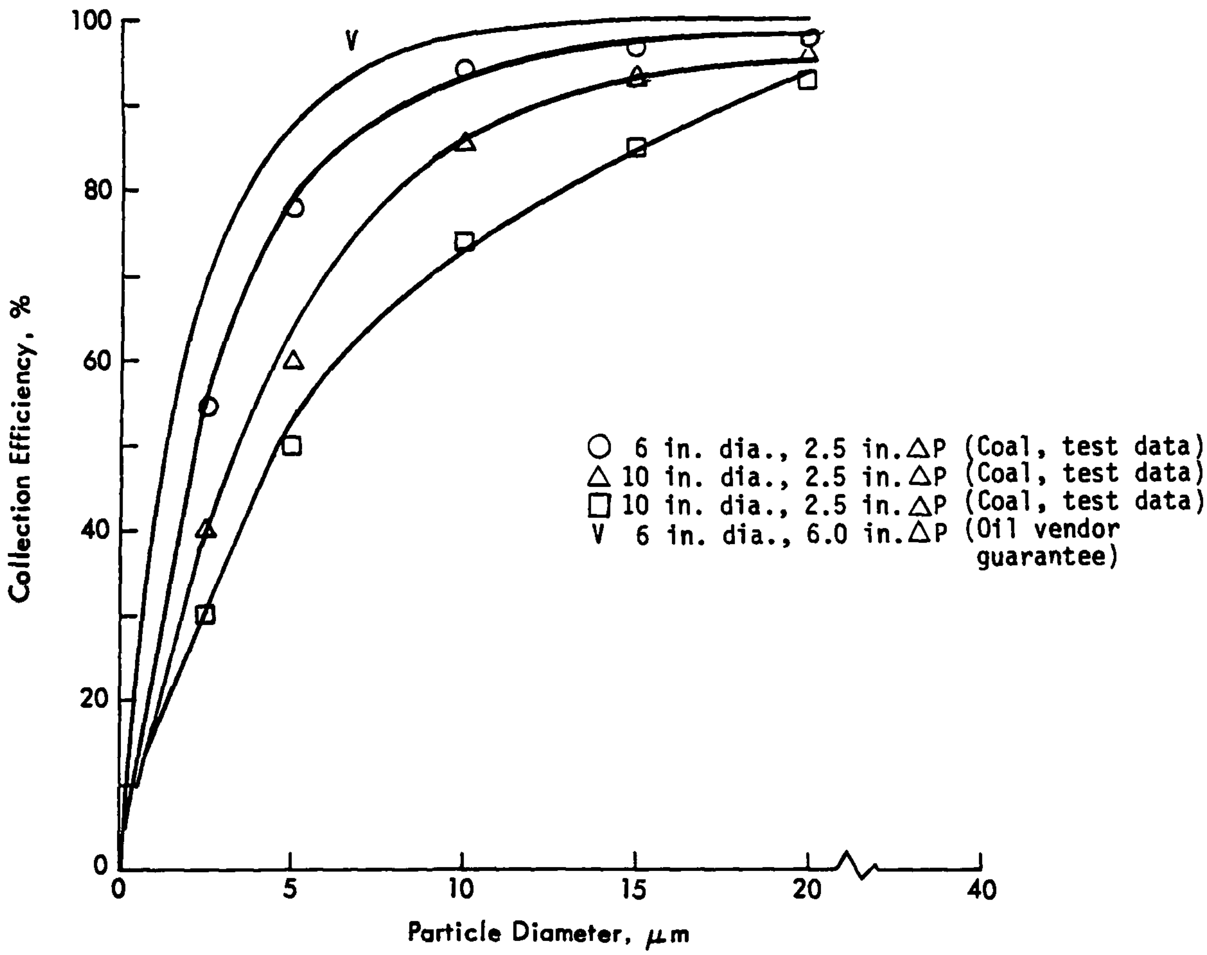


Figure 4.1-4. Fractional efficiency data for cyclone collection of fly ash from coal- and oil-fired electric utility boilers.[9]

of potentially corrosive flue gas components. Primary considerations to be used in evaluating the construction materials needed are:[56]

- Gas temperature
- Abrasiveness of the dust particles
- Corrosiveness of the gas stream

If the gas stream is corrosive or the dust particles are abrasive it may be necessary to use a stainless steel alloy instead of carbon steel in the construction of the cyclone.

It is important to accurately monitor the pressure drop across the cyclone so that any plugging can be detected. In addition, the interior should be inspected on a regular basis for corrosion damage, plugged tubes, or defective gaskets. Another area of maintenance that is critical to efficient mechanical collector performance is the discuovery and remedy of air leakage into the collector. Leakage can occur at the hopper access door, hopper discharge valve, hopper casing, or the lower tube sheet. Air leakage into a collector hopper can result in reentrainment or collected particles, thus reducing collector performance.

One of the most detailed sources of information on mechanical collector performance is a study conducted jointly by the American Boiler Manufacturer's Association (ABMA), the Department of Energy (DOE), and EPA. This study was performed on coal-fired boilers. However, the conclusions on factors affecting mechanical collector performance should be applicable to NFFBs also. Several stoker-fired boilers equipped with mechanical collectors were tested in this study and particulate emissions tests were conducted at both the boiler and the mechanical collector outlets. Based on a review of this data, the following conclusions can be made about the effect of boiler operating parameters on mechanical collector performance:[59]

- Figure 4.1-4a shows that, for three similar coals, mechanical collector <u>efficiency</u> remained relatively constant with changes in boiler load above about 60 percent. However, there was

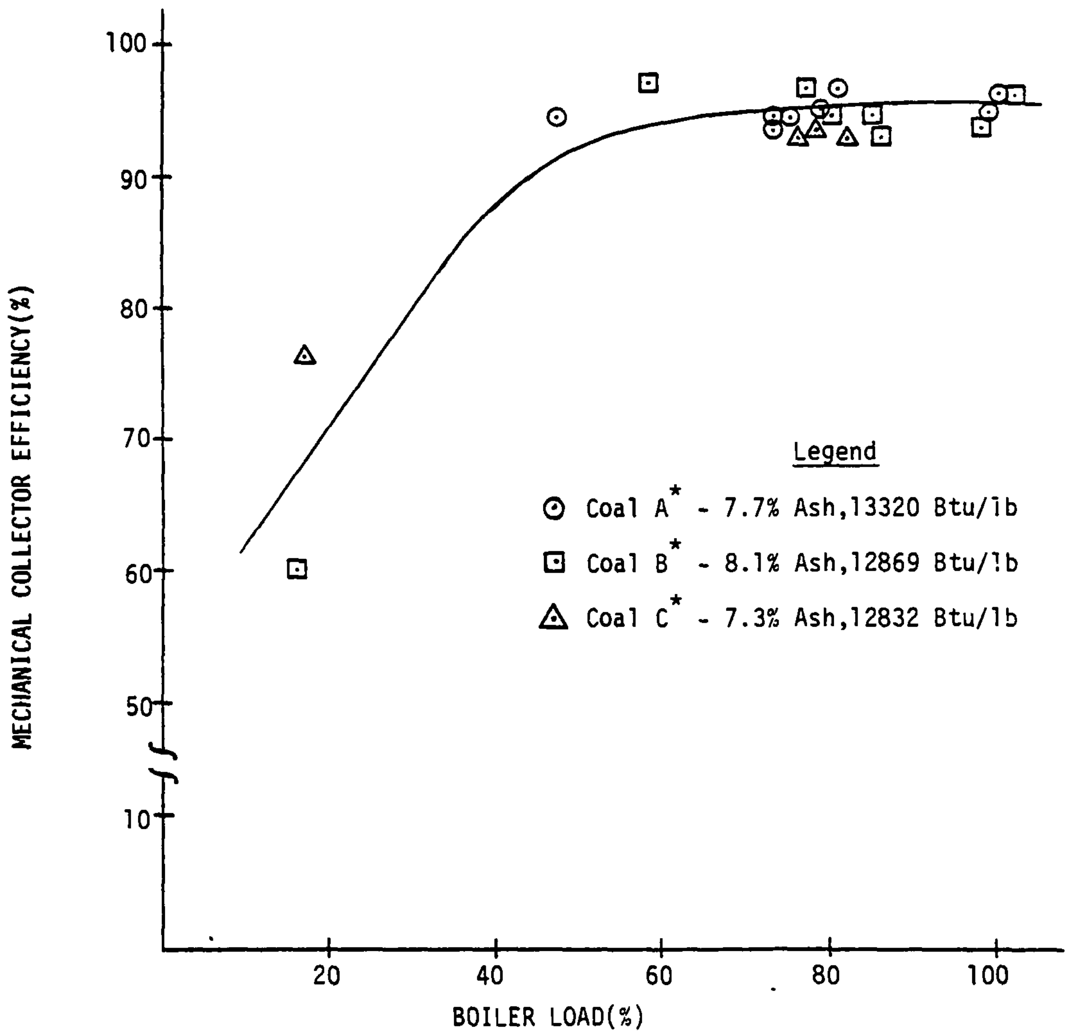


Figure 4.1-4a. Mechanical collector efficiency versus boiler load (spreader stoker boilers).[59]

*Note: Data shown is from two different boiler collector systems. Coal A was fired in one, while coals B and C were fired in the other .

significant drop in collector efficiency at loads of approximately 50 percent and less.

- There was considerable scatter in the test data for some units as a result of variable process conditions and fuel types. The results showed that particulate matter emissions from both the boiler and mechanical collector (in terms of $lb/10^6$ Btu) tended to increase as the boiler load increased. This trend can be seen in Figure 4.1-4b where boiler and mechanical collector outlet emissions are plotted as a function of boiler load.[10] Although these figures illustrate emissions from a single boiler, they are representative of the overall trends from the data set.

- Figure 4.1-4c also illustrates that controlled emissions from this boiler remained fairly steady, but showed a trend of increased emissions at boiler loads greater than 50 percent. This trend was also seen for other boilers. The sharp increase in emissions at very low loads was attributed to the reduced mechanical collector efficiency at the unusually low firing rate obtained at this one site.

- In general, no significant correlations were observed between mechanical collector performance and overfire air levels, or excess air levels.

- The data did show that mechanical collector collection efficiency was lower when there were relatively high percentages of small particles (less than 10 microns in diameter) at the inlet to the collector. However, no correlations were observed between boiler load, excess O_2, or overfire air levels and the resulting particle size distribution.

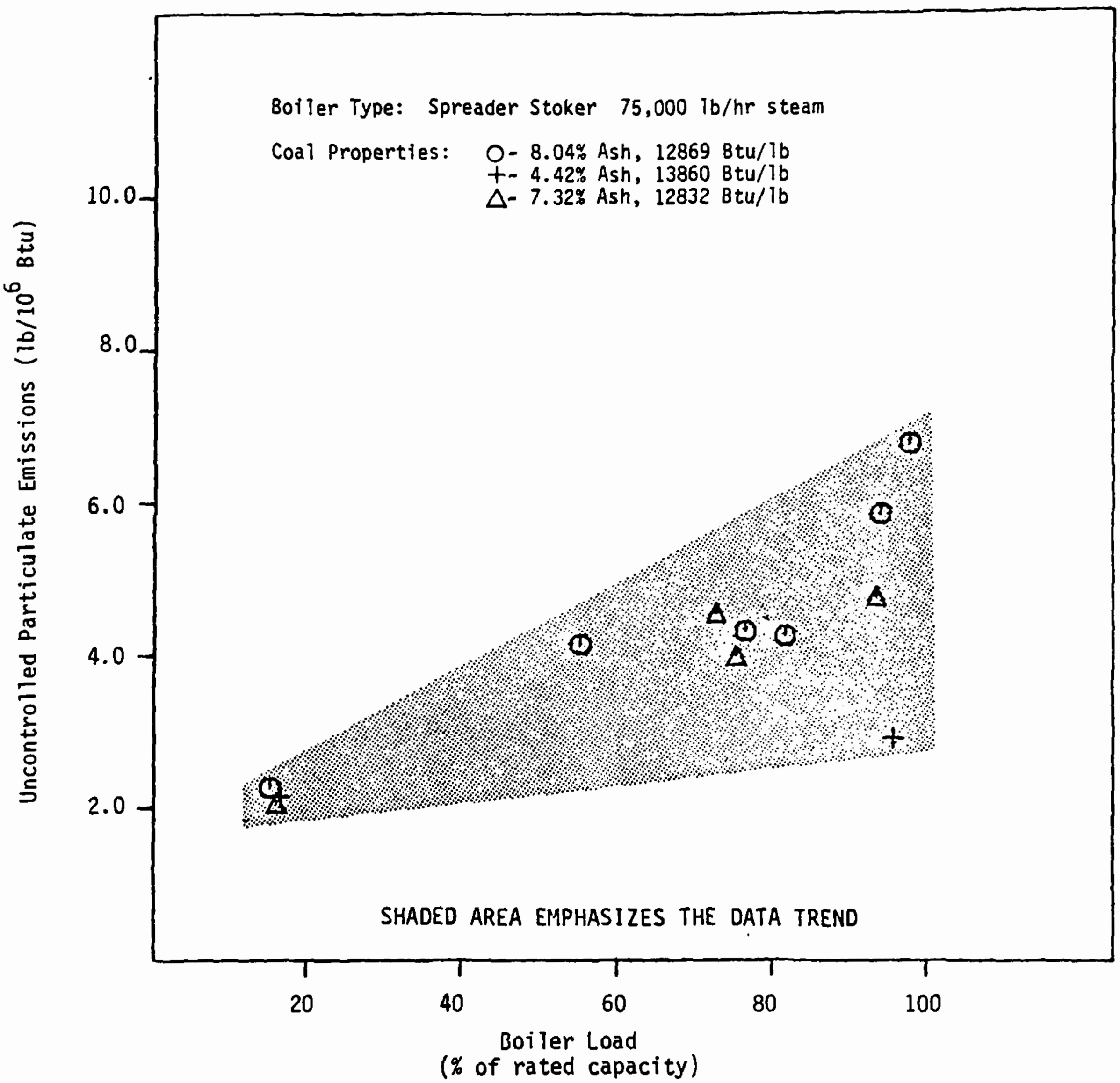


Figure 4.1-4b. Uncontrolled particulate emissions versus boiler load.[10]

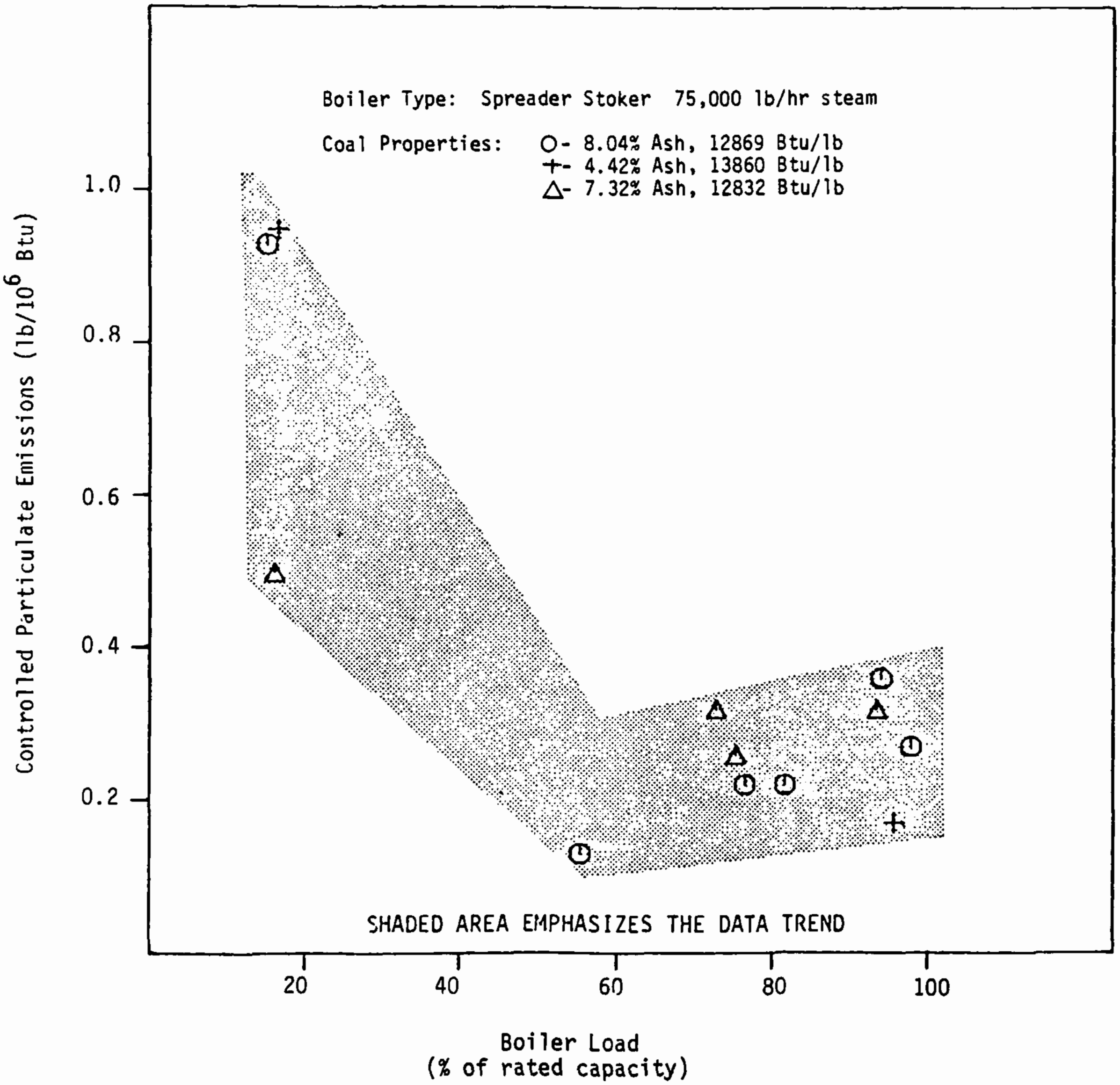


Figure 4.1-4c. Controlled particulate emissions versus boiler load.[10]

4.1.2 Wet Scrubbing

4.1.2.1 Process Description. A wet scrubber is a collection device which uses an aqueous stream or slurry to remove particulates and/or gaseous pollutants.

There are three basic mechanisms involved with collecting particulate in wet scrubbers. These mechanisms include the interception, inertial impaction and diffusion of particles on droplets. The inertial impaction and interception effects dominate at large particle diameters, while the diffusion effects dominate at small particle diameters.

Scrubbers are usually classified by energy consumption (in terms of gas-phase pressure drop). Low-energy scrubbers, represented by spray chambers and towers, have pressure drops less than 1.3 kPa (5" of water). Medium-energy scrubbers such as impingement scrubbers have pressure drops of 1.3-3.7 kPa (5-15" of water). High-energy scrubbers such as high-pressure drop venturi scrubbers have pressure drops exceeding 3.7 kPa (15" of water). The most common scrubbers used for "moderate" removals of particulate matter are medium-energy impingement and venturi scrubbers. Greater removals of particulate matter are usually achieved with high-energy venturi scrubbers.

A typical impingement scrubber, also known as an orifice, self-induced spray, or entrainment scrubber, is shown in Figure 4.1-5. This scrubber features a shell that retains liquid so that gas introduced to the scrubber impinges on and skims over the liquid surface to reach the gas exit duct. Atomized liquid is entrained by the gas and acts as a particle collecting and mass transfer surface. Particle collection results from inertial impaction caused by both the gas impinging on the liquid surface and by the gas flowing around the atomized drops.

Venturi scrubbers are rapidly gaining widespread popularity, especially in view of the current emphasis on the collection of submicron particles.[12] In a typical venturi scrubber, which is illustrated in Figure 4.1-6, the particle-laden gas first contacts the liquor stream in the core and throat of the venturi section. The gas and liquor streams then pass through the annular orifice formed by the core and throat, atomizing the liquor into droplets which are impacted by particles in the gas stream. Impaction

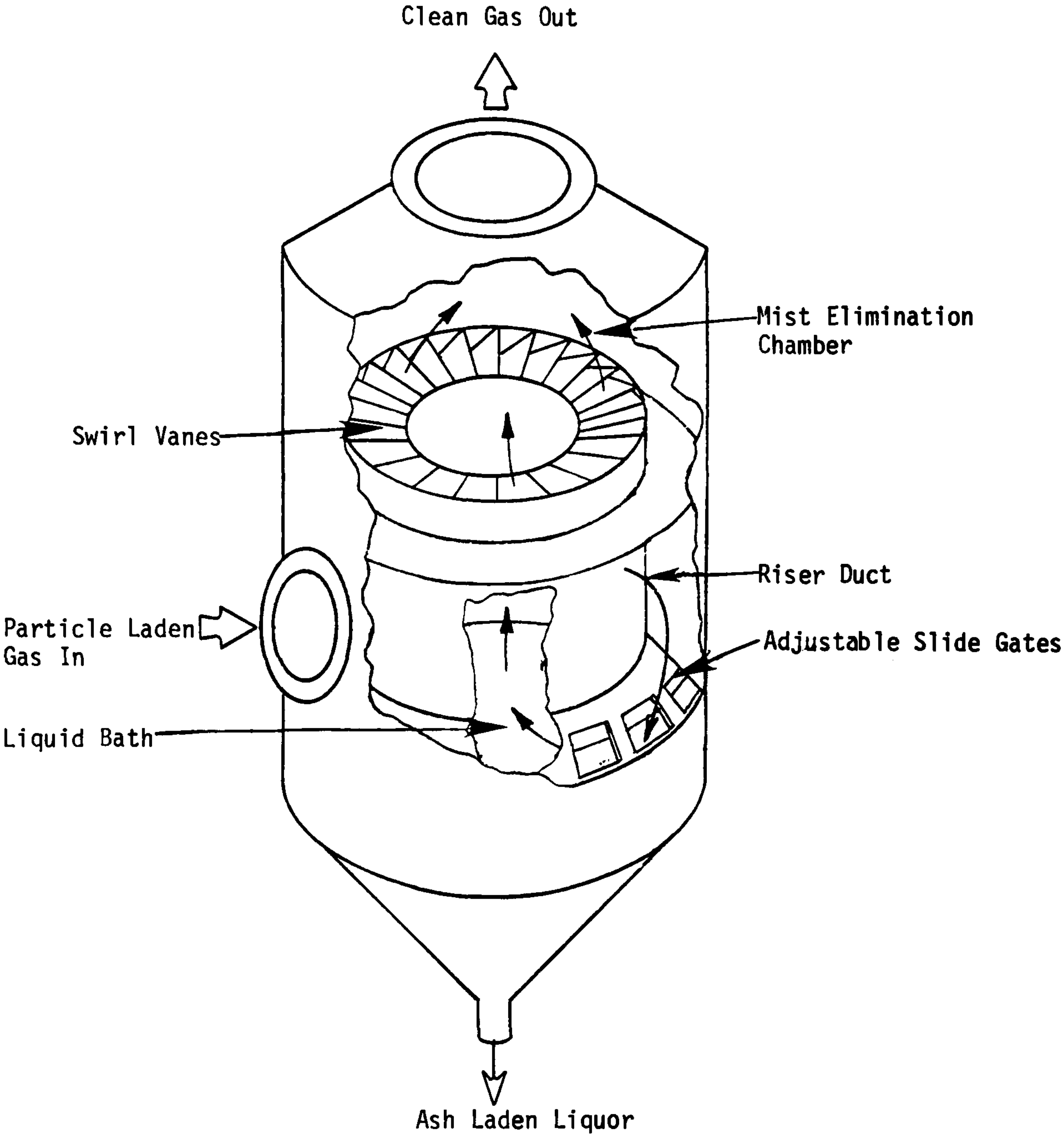


Figure 4.1-5. Schematic of a typical impingement scrubber [11]

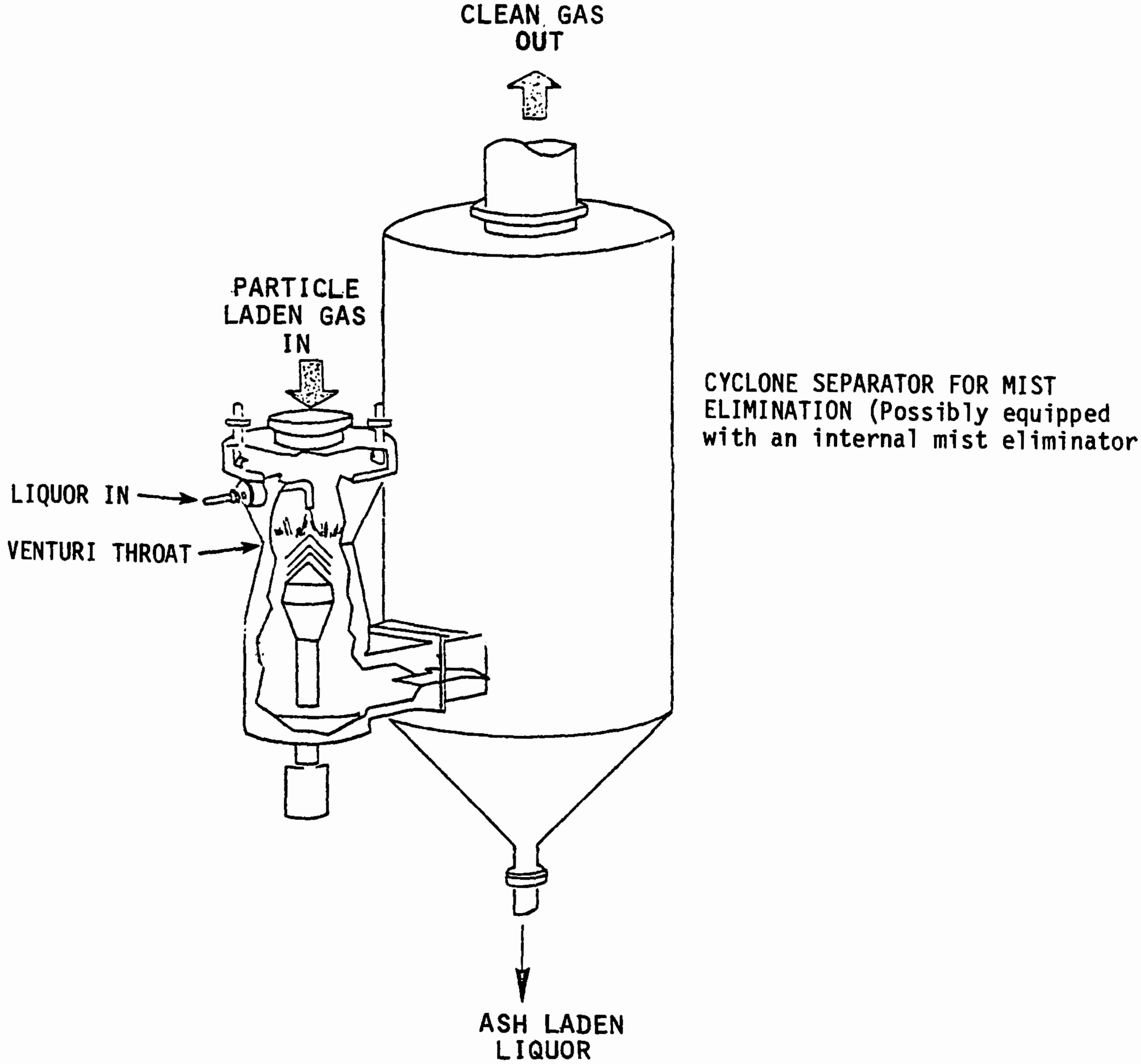


Figure 4.1-6. Variable-throat venturi scrubber.[13]

results mainly from the high differential velocity between the gas stream and the atomized droplets. The droplets then are removed from the gas stream by centrifugal action in a cyclone separator and (sometimes) mist elimination section.[14]

Corrosive species in the flue gas (e.g., SO_2, SO_3, and HCl) will be absorbed to some extent into the scrubbing liquor. In some particulate scrubbers recirculation of low pH (pH less than 3) liquors have caused corrosion problems. Consideration must therefore be given to the construction materials used in the contactor. Fiberglass reinforced polyester or rubber-lined steel are the most commonly-used materials. These materials are also resistant to the errosive effects of the slurries which must be handled in wet scrubbing systems.

A common operating technique used to prevent low pH conditions is the addition of an alkali compound. The addition of an alkali compound to the wet particulate scrubber for pH control results in the recirculation of a scrubbing slurry with sufficient dissolved alkalinity to absorb significant amounts of SO_2 from the flue gas, thus forming a combined particulate matter/SO_2 removal system. For example, if sodium carbonate (Na_2CO_3) is used as the chemical for pH neutralization, the overall chemical reaction that occurs is the following:

$$Na_2CO_3 + SO_2 \rightarrow Na_2SO_3 + CO_2 \qquad (4.1.2\text{-}1)$$

Alternative flue gas desulfurization processes are described in Section 4.2.

4.1.2.2. Development Status and Applicability to Nonfossil Fuel Fired Boilers. Particulate control by wet scrubbing is a well-established technology. The use of wet scrubbers in Great Britain for cleaning boiler flue gases dates back to 1933. However, this technology has only been adapted within the last 20 years to control fly ash emissions from industrial boilers in the U.S. Since the early 1960s, wet scrubbing has been applied to fossil fuel-fired boilers in the U.S. for combined particulate collection and SO_2 absorption.[15] As reported in Section 4.2.1, four NFFBs cofiring wood and fossil fuels use wet scrubbing for both PM and SO_2 removal.

Wet scrubbers are widely used to remove particulate matter from wood and bagasse boiler flue gases. Scrubbers applied to these boilers are often installed downstream of multitube cyclones. No successful scrubber applications to MSW or RDF boilers exist: the fine particulate in these boiler exhausts can be removed only by very high-energy scrubbers which must be constructed of expensive corrosion-resistant materials. The only MSW boiler that used a wet scrubber replaced the scrubber with an electrostatic precipitator.

4.1.2.3. Factors Affecting Performance. Factors that affect the performance of typical wet scrubbers are:

- contacting power (gas phase pressure drop and liquid nozzle pressure drop)
- liquid to gas ratio (L/G)
- carry out of scrubber liquor
- particle size distribution
- PM grain loading in gas.

The contacting power of the wet scrubber is usually the major factor affecting particulate removal.[16] In most scrubber applications the contacting power is measured by the gas phase pressure drop. As shown by Figures 4.1-7 and 4.1-8, removal efficiency increases with increasing gas phase pressure drop: greater pressure drops create smaller liquid drops that are more efficient in collecting PM. In certain types of wet scrubbers (such as ejector venturi scrubbers) atomization of the liquid is accomplished using a high pressure spray. For these types of scrubbers, the contacting power is indicated by the liquid nozzle pressure drop and not the gas phase presure drop.

High-pressure drop scrubbers may show reduced removal efficiency due to carry out of particulate-laden scrubber liquor droplets.[18] These droplets evaporate and release the suspended particulate matter back into the flue gas. High-pressure drop scrubbers should thus be equipped with mist eliminators to ensure adequate separation of the gas and liquid droplets.

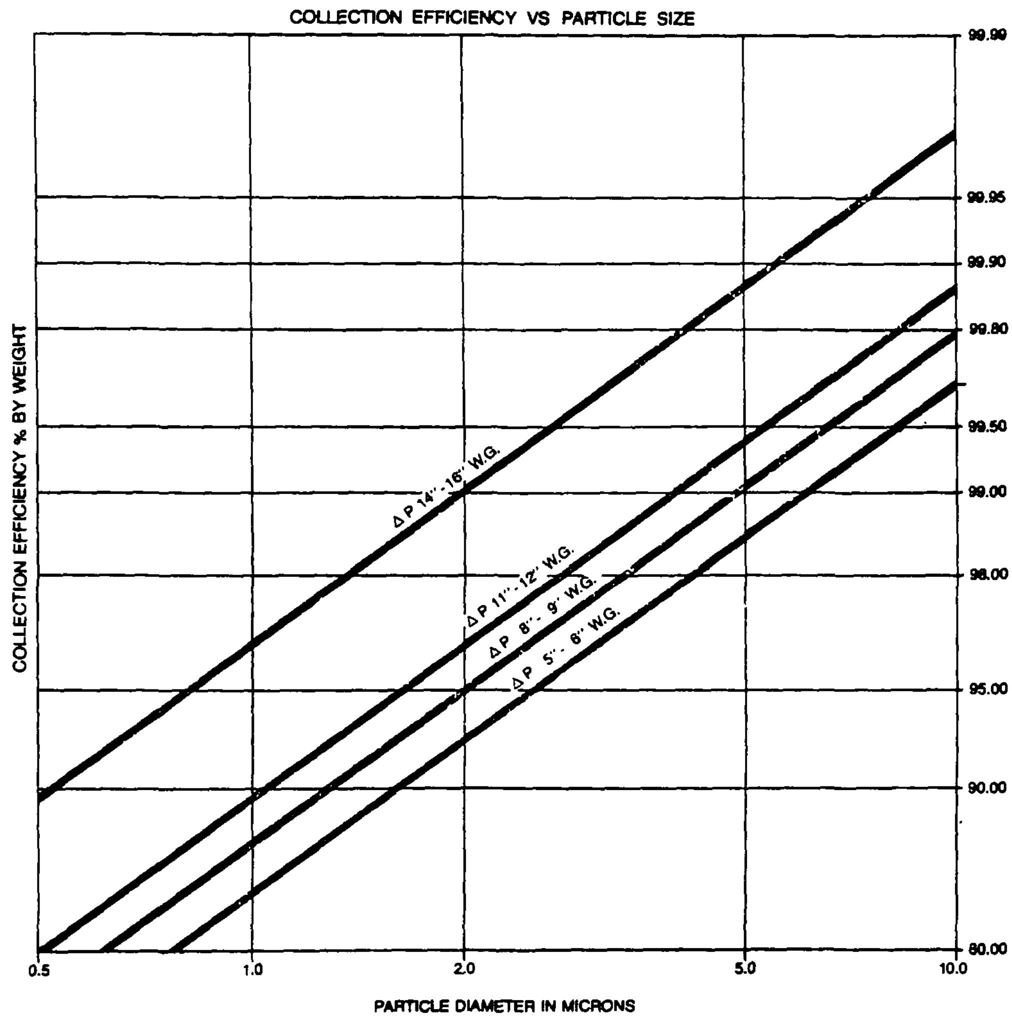


Figure 4.1-7. Impingement scrubber fractional efficiency curves (Courtesy of the Western Pricipitation Division of Joy Manufacturing Company)[11]

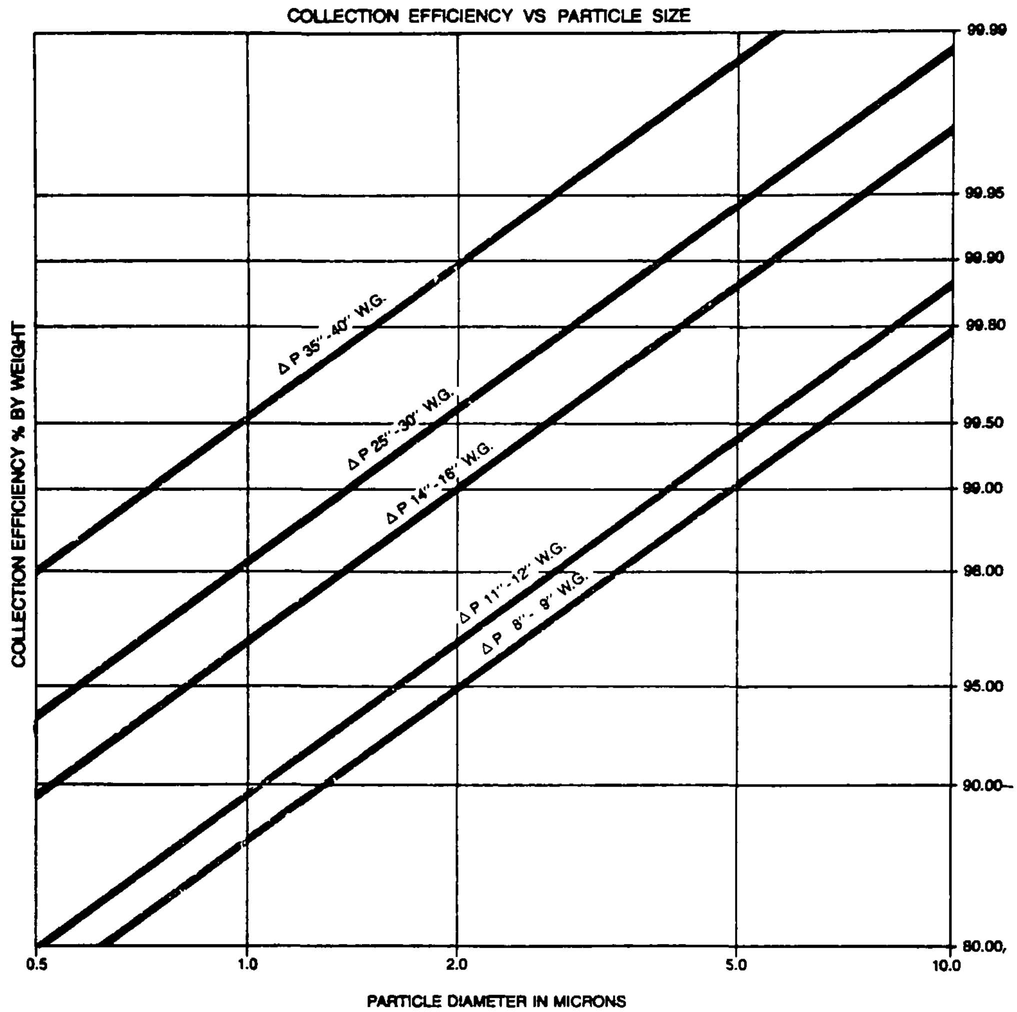


Figure 4.1-8. Venturi scrubber fractional efficiency curves (Courtesy of the Western Precipitation Division of Joy Manufacturing Company)[17]

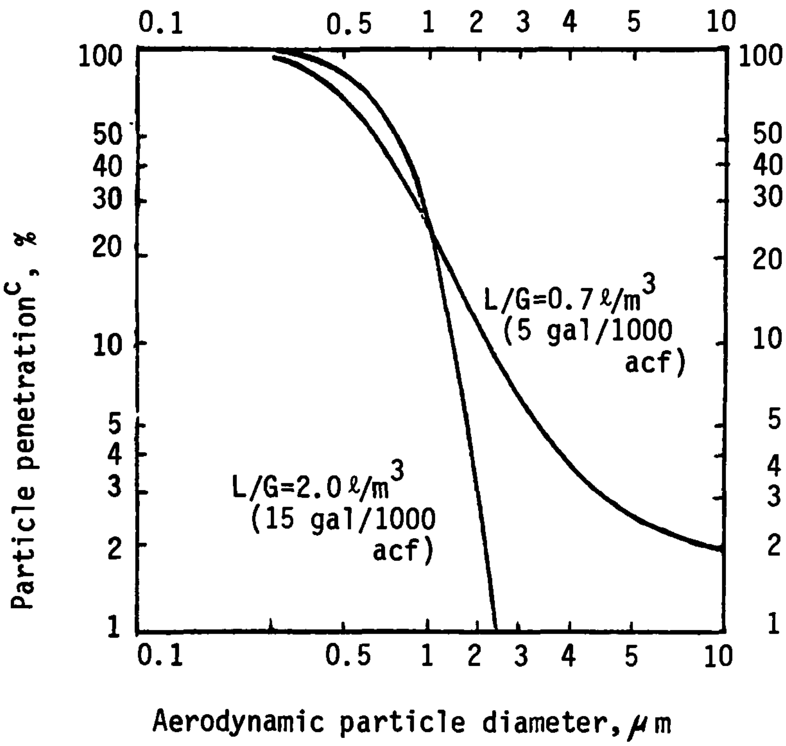
Where once through scrubbing liquid is used, the efficiency reduction is not likely to be as large since the percentage of solids in the liquor is generally lower than when recycled scrubbing liquor is used.

If the liquid rate to the scrubber is sufficient to completely sweep the gas stream with droplets without flooding the scrubber, scrubber performance is relatively insensitive to variations in the liquid-to-gas ratio.[19] Increases in the L/G generally increase scrubber efficiency but the performance increases are usually small. Figure 4.1-9 illustrates the impact on removal efficiency of changes in L/G for a venturi scrubber operating at a given pressure drop and two different liquid-to-gas ratios.

As shown in Figures 4.1-7 through 4.1-9, scrubber performance depends on the particle size distribution of the PM to be collected. These figures show that collection efficiency varies directly with particle size, with larger particles collected at greater efficiency.

Scrubber performance also depends on the PM grain loading. PM loadings exceeding the scrubber design loading could overload the scrubber and reduce PM removal efficiency. Scrubber efficiency could be improved by increasing the gas velocity (or pressure drop) and L/G. Alternatively, precleaners such as cyclones could be used upstream of the scrubber to reduce the PM loadings to the scrubber.

Venturi scrubber applications generally include a variable throat system (enabling control of pressure drop) to enable a constant efficiency to be maintained at varying boiler loads.[20] Impingement scrubbers similarly allow control of pressure drop by adjusting the peripheral gas nozzle. Pressure drops across venturi throats generally range from 1.5 to 7.5 kPa (6 to 30 w.c.) in boiler applications. Gas velocities through the venturi throat may range from 61 to 183 m/s (200 to 600 ft/s) while liquid-to-gas ratios (L/G) vary from 1.0 to 2.0 liters/m^3 (8 to 15 gal/1000 ft^3).[21] Pressure drops in impingement scrubbers range from about 0.8 to 4 kPa (3 to 16 in. w.c.) while L/Gs vary from about 0.4 to 1.3 liters/m^3 (3 to 10 gal/1000 ft^3).



[a]Reference 19.

[b]Gas phase pressure drop for both scrubbers is 2.5kPa (10 in. w.c.)

[c]Particle penetration is 100 - Particle removal efficiency.

Figure 4.1-9. Venturi scrubber fractional efficiency curves for scrubbers operating at different liquid-to-gas ratios.[a,b]

4.1.3 Fabric Filtration (Baghouses)

4.1.3.1 Process Description. A typical baghouse is portrayed in Figure 4.1-10. As the inlet gas passes through the fabric filters, dust particles in the inlet gas are retained on the fabric filters by inertial impaction, diffusion, direct interception, and sieving. The first three processes prevail only briefly during the first few minutes of filtration with new or recently cleaned fabrics, while the sieving action of the dust layer accumulating on the fabric surface soon predominates. This is particularly true at high dust loadings, greater than 1 g/m^3 (0.437 gr/ft^3). The sieving mechanism leads to high efficiency collection unless defects such as pinhole leaks or cracks appear in the filter cake.[23]

In fabric filtration both the collection efficiency and the pressure drop across the bag surface increase as the dust layer on the bag builds up. Since the system cannot continue to operate with an increasing pressure drop, the bags are cleaned periodically. Cleaning typically occurs in one of three ways. In shaker cleaning, the bags are oscillated by a small electric motor. The oscillation shakes most of the collected dust into a hopper. In reverse flow cleaning, backwash air is introduced to the bags to collapse them and fracture the dust cake. Both shaker cleaning and reverse flow cleaning require a sectionalized baghouse to permit cleaning of one section while other sections are functioning normally. The third cleaning method, reverse pulse cleaning, does not require sectionalizing. A short pulse of compressed air is introduced through venturi nozzles and directed from the top to the bottom of the bags. The primary pulse of air aspirates secondary air as it passes through the nozzles. The resulting air mass expands the bag and fractures the cake.

4.1.3.2 Development Status and Applicability to Nonfossil Fuel Fired Boilers. Fabric filtration is a well established technology with early industrial process applications dating back to the late 1800s. However, application to boiler flue gas has been a recent development with the first successful installations designed in the later 1960s and early 1970s.

Few full-scale baghouses have been applied to nonfossil fuel fired boilers. About seven baghouses are installed on wood-fired boilers but no

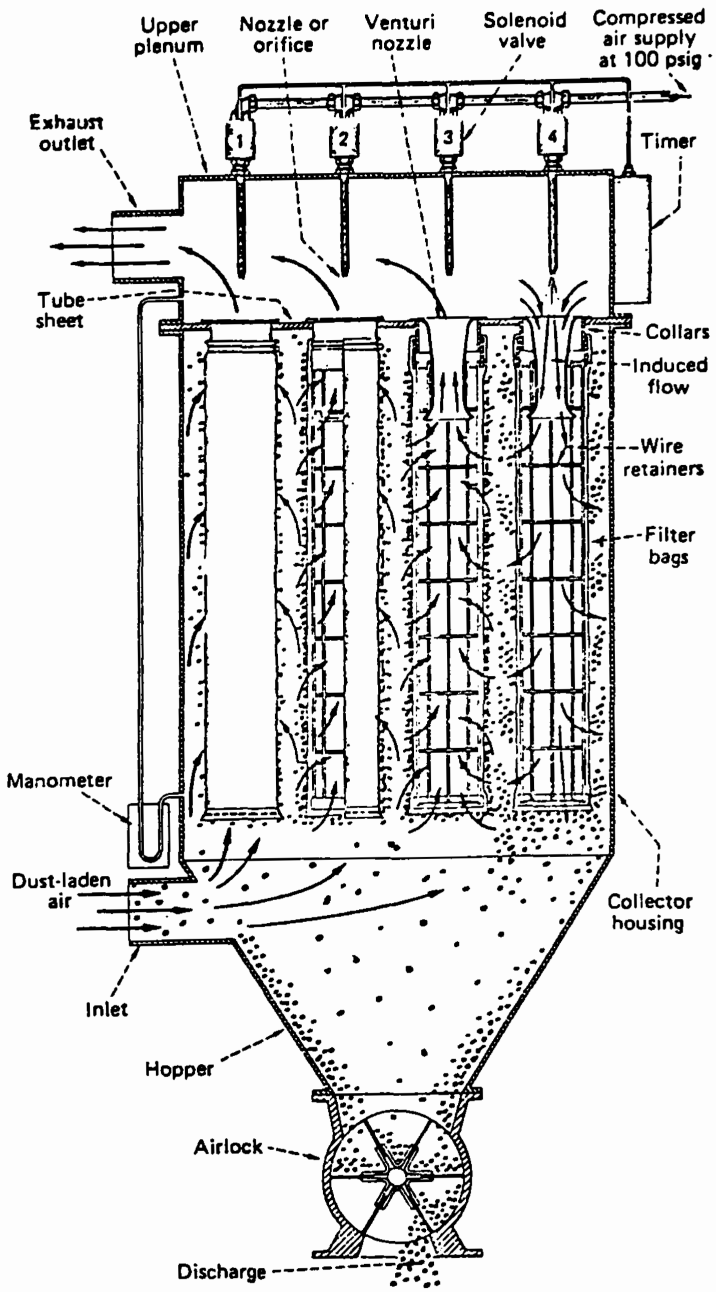


Figure 4.1-10. Schematic of a typical pulse-jet fabric filter baghouse (Courtesy of Mikropul Corporation)[22]

baghouse applications exist on bagasse, MSW, or RDF boilers. However, one baghouse operates successfully on an MSW incinerator. The principal drawback to fabric filtration, as perceived by potential users, is a fire danger arising from the collection of a combustible carbonaceous fly ash.[24-27]

Two of the seven baghouses successfully applied to wood-fired boilers collect fly ash that is mainly salt (up to about 70%).[27-30] (As described in Chapter 3, high salt fly ash is emitted from the combustion of salt-laden wood. Salt-laden wood or wood waste results from the storage of logs in salt water.) This type of fly ash may pose a smaller fire threat due to a quenching effect of the salt.

Three of the five baghouses collecting non-salty fly ash from wood-fired boilers are operating successfully and have experienced no baghouse fires. The other baghouses collecting non-salty, highly carbonaceous fly ash are now operating successfully but both of these baghouses have previously experienced baghouse fires.[31]

One of the baghouses that has experienced fires is used on a very small wood-fired boiler (0.1 MW or 0.4 x 10^6 Btu/hr on a steam out basis). The other baghouse that has experienced fires is used on a larger spreader stoker wood-fired boiler.

Although the baghouse on the spreader stoker is now operating successfully,[26] two fires earlier resulted in extensive damage to the baghouse and bags. The first fire resulted from the contact of carbonaceous ash with air leaked into the baghouse from the pneumatic ash conveying system. This fire hazard was eliminated by locating the air fan downstream of the baghouse, so that the conveyor air pipe was at lower pressure at the baghouse ash hopper valve relative to the pressure in the baghouse. The second fire resulted from the contact of air with hot carbonaceous fly ash accumulating in the baghouse hopper. This fire hazard has been reduced by improved operating procedures that monitor ash buildup. The current operation of the baghouse without fires can be atrtributed to:

- water quenching the gas stream upstream of the baghouse
- minimizing the in-leakage of air to the hot carbonaceous fly ash
- establishing a filter cleaning sequence that prevents the build-up of a thick filter cake
- bypassing the baghouse during the intermittent operations of sootblowing and cyclone cleaning, when sparks are likely to reach the baghouse
- removing large burning particles of fly ash in multitube cyclone precleaners.

A pilot baghouse formerly used on an MSW-fired boiler also had fires. That baghouse also experienced bag blinding during startup and during periods when the flue gas moisture content was unusually high.[25] As described below bag blinding can be avoided by careful design and operation.

In addition to the steps taken above to reduce fire hazard, a baghouse owner may add special fire protection measures. The baghouse can be fitted with a sprinkler system to quench the baghouse and bags when fire occurs. Although the bags will need to be replaced after a quench, major structural damage may be avoided. A special protection system may also be added to quench sparks before they reach the baghouse. Such a system consists of a flame detector and a supply of extinguishing agent such as water, steam, or carbon dioxide. The extinquishing agent is applied only long enough to quench sparks.[32-33] Although the above measures seem likely to reduce fire danger, they have not been demonstrated in NFFB applications.

4.1.3.3 Factors Affecting Performance. The most important design factor for a baghouse is the air-to-cloth ratio (A/C). This parameter relates the volume of gas filtered (m^3/min or acfm) to the available filtering area (m^2 or ft^2). This is, in effect, the superficial velocity of the gas through the filtering media. Air-to-cloth ratios for the pulse jet cleaning systems applied to wood-fired boilers range from 0.9-1.5 m/min (3-5 ft/min).[26-30]

Baghouse outlet loading does not vary greatly as a result of changes in gas flowrate for a given boiler application. As the flowrate is reduced from the design rate (presumably the flow at rated capacity) the A/C decreases. Filtration generally improves with decreasing A/C, especially if the unit collects substantial quantities of small particles and the cleaning cycle is triggered by attainment of a predetermined pressure drop.[35] Hence, a baghouse that meets specifications at the design flowrate should have equal or lower outlet grain loadings at reduced flowrates.

Fabric filters can operate at efficiencies greater than 99.9 percent with pressure drops of 0.5 to 1.5 kPa (2 to 6 in w.c.).[35] Increases in the pressure drop may imply that more frequent cleaning is needed.

During baghouse operation it is essential that baghouse temperatures be maintained above the water dewpoint of the gas so that condensation will not occur on the compartment walls and filter surfaces. In the latter case, resultant plugging or blinding may restrict gas flow and cause irreversible bag damage. This is most likely to occur during transient operations such as startup, shutdown or fluctuating loads. If acid condensation occurs after shutdown, the acid mist moisture eventually evaporates and crystallization on the bag filter may occur. In this situation, the bag filter may become brittle and subject to cracking when stress is once again applied.[60] Bypassing or preheating the baghouse prior to system startup, continuous gas recirculation during brief shutdowns, and/or sufficient insulation on the baghouse and duct should minimize condensation problems.[34]

Bag material is chosen to withstand the specific flue gas environment expected to be encountered. Mechanical strength is also an important factor with respect to the mechanical demands exerted on the fabric by the gas flow and cleaning system. Acidic species such as SO_2 and HCl attack Nomex.[30] Although many of the baghouse applications on wood-fired boilers use Nomex material, fiberglass or Teflon-coated fiberglass is recommended because of the acidic chlorides possibly present in the flue gas.[27,28,30]

In general, although nonwoven fabrics (i.e., felt) are the most efficient particle collectors, they are the most difficult to clean. Texturized filament fabrics (i.e., teflon coated fiberglass) represent a middle ground in cleanability, durability and efficiency.[61]

Most fabrics are efficient in collecting a wide range of sub-micron particles. Emission tests conducted on a 63,100 kg steam/hr (139,000 lb steam/hr) spreader stoker firing coal equipped with a reverse-air fabric filter demonstrated that for particles in the 0.02 to 2 micron range, fabric filter fractional efficiency did not fall below 99.9 percent.[63]

4.1.4 Electrostatic Precipitation

4.1.4.1 Process Description. Particulate collection in an electrostatic precipitator occurs in three steps: suspended particles are given an electrical charge; the charged particles migrate to a collecting electrode of opposite polarity while subjected to a diverging electric field; and the collected particulate matter is dislodged from the collecting electrodes.

Charging of the particles to be collected is usually caused by ions produced in a high voltage d-c corona. The electric fields and the corona necessary for particle charging are provided by high voltage transformers and rectifiers. Removal of the collected particulate matter is accomplished mechanically by rapping or vibrating the collecting electrodes. Figure 4.1-11 shows a cross-sectional view of a typical ESP.

4.1.4.2 Development Status and Applicability to Nonfossil Fuel Fired Boilers. Electrostatic precipitator technology is commercially developed and dates back to the early 1900s. ESPs treating flue gas flow rates as low as 8500 m^3/hr (5000 acfm) are commercially available.[37] Because of their modular design, ESPs can be expanded to treat flue gas from even the largest industrial boilers. ESPs have been installed on utility boilers with flue gas flow rates as high as 10,000,000 m^3/hr. Application of an ESP to an industrial boiler should have no adverse effect upon boiler operation. However, boiler operation can have a significant impact upon ESP performance.

The suitability of particulate collection by electrostatic precipitation depends primarily on the resistivity of the particles. Particles with resistivities in the range of 5×10^3 to 2×10^{10} ohm cm have been shown by experience to be the most suitable for electrostatic precipitation.[38] Particles with lower resistivities will give up their charge too easily and will be re-entrained in the gas stream. Particles with higher resistivities

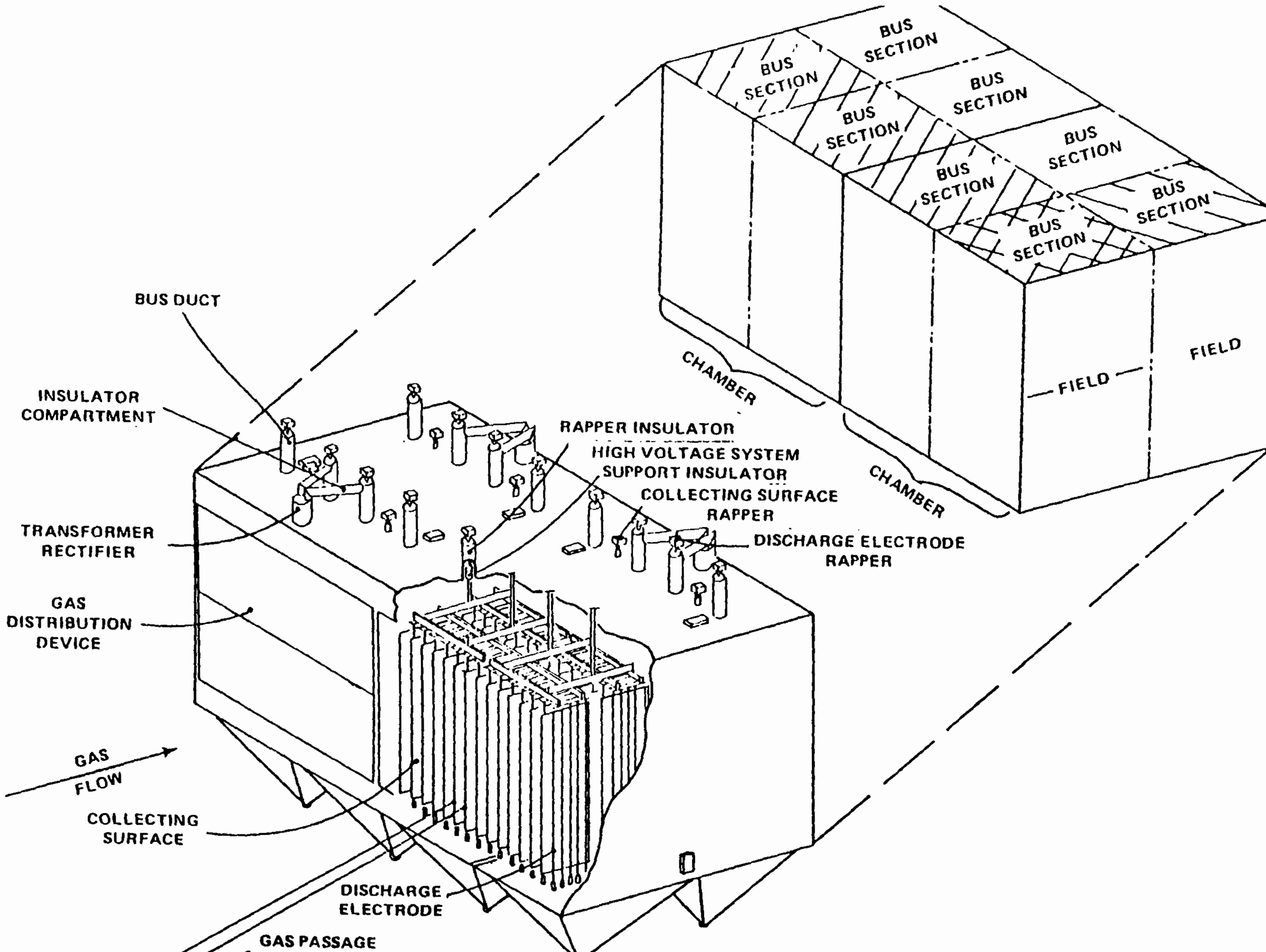


Figure 4.1-11. Typical precipitator cross section.[36]

will coat the collecting plates and will be hard to dislodge. The plates will thus have diminished ability to attract charged particles.

Electrostatic precipitators are currently used on boilers fired with wood, MSW, or RDF. No ESPs have been applied to bagasse-fired boilers. ESPs applied to wood-fired boilers are sometimes used downstream of cyclone precleaners while ESPs on MSW- or RDF-fired boilers are usually the only particulate control device.

4.1.4.3 Factors Affecting Performance. The performance of ESPs depends on 1) amount of available collecting surface, 2) gas flow rate, 3) particulate resistivity, 4) particle size distribution, 5) gas velocity distribution, 6) rapping intensity and frequency, and 7) electrical field strength. Because the individual effects of these factors on ESP performance are difficult to model, ESP performance is typically predicted from an empirical three-parameter equation. Classically, the performance of ESPs has been predicted with the Deutsch-Anderson equation:

$$\eta = 1 - \exp [- W_e(A/V)] \qquad (4.1.4\text{-}1)$$

where η = collection efficiency
W_e = average migration velocity, ft/m
V = gas flow rate, ft^3/m
A = collecting plate area, ft^2.

The ratio A/V is known as the specific collection area (SCA) and is usually expressed in $m^2/(m^3/s)$ or $ft^2/1000$ acfm. Practical values of SCA range from 20 to 160 $m^2/(m^3/s)$ (100 to 800 $ft^2/1000$ acfm) for most field applications.[41] SCA is an important design and operating parameter for an ESP. Collection efficiency improves as SCA increases, but the ESP becomes larger and more expensive.

The average migration velocity or precipitation rate is a function of particle size distribution and resistivity, gas velocity distribution, rapping intensity and frequency, and electrical field strength. Figure 4.1-12 shows the dependence of precipitation rate on particle

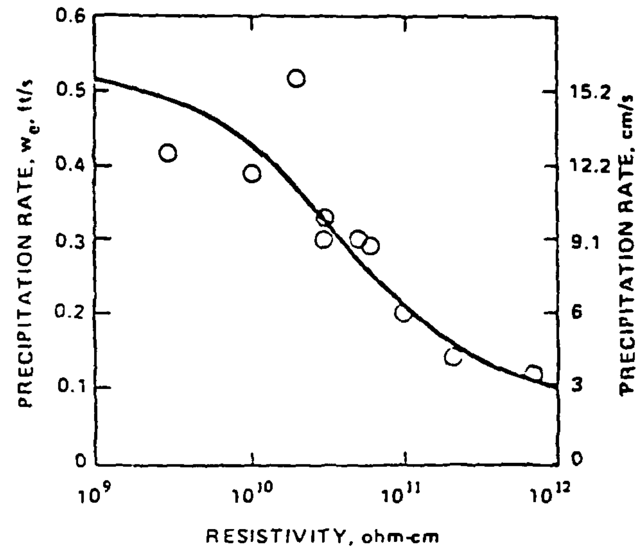


Figure 4.1-12. Relationship of particle resistivity and precipitation rate.[39]

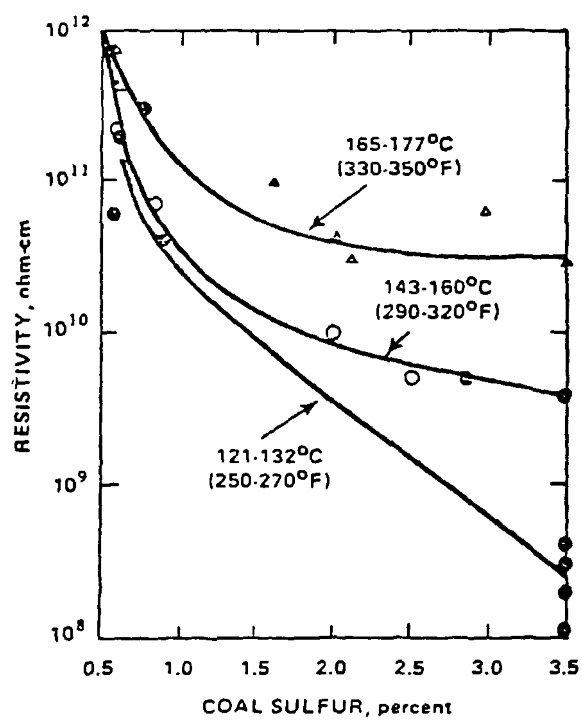


Figure 4.1-13. Fly ash resistivity versus coal sulfur content for several flue gas temperature bands.[40]

resistivity. Figure 4.1-13 is an example of the dependence of fly ash resistivity on temperature and fuel sulfur content.

Data available on the resistivities of nonfossil fuel fly ashes are reported in Figure 4.1-14 and in Table 4.1-1. Although the resistivity data generally support the suitability of particulate collection by electrostatic precipitation, a few limitations exist. Wood fly ash containing a large amount of salt could have unsuitably high resistivities at temperatures below 506 to 533K (450-500°F) if the gas moisture content falls below 10 percent.[42] Similarly, wood or RDF cofired with low sulfur fossil fuels could have unsuitably high resistivities, depending on the resistivity of the coal fly ash. In cofiring wood with a fossil fuel, ESP sizing depends mainly on the fossil fuel fly ash resistivity if the fossil fuel is low in sulfur since the wood fly ash is relatively easy to collect.[42] Cofiring RDF with low sulfur coal is potentially a more difficult precipitation application because both the coal and the RDF have high resistivities.

In many cases, field data indicate lower ESP efficiencies than predicted by the Deutsch-Anderson relationship. To account for the observed particle collection levels, White[43] designates the empirical relationship:

$$\eta = 1 - \exp\left[- (w_k \, A/V)^{0.5} \right] \qquad (4.1.4\text{-}2)$$

as a more realistic predictor of particulate collection efficiency. The exponent, 0.5, is applicable when the ESP system is handling coal fly ash. In Equation 4.1.4-2, the term w_k is an "effective" migration velocity computed from experimental measurements. Use of this parameter results in a better estimate of SCA at high removal efficiencies.[50]

Figure 4.1-15 shows how the precipitation rate varies with gas temperature. The variation occurs due mainly to the effects of temperature on fly ash resistivity. Figure 4.1-16 shows how the field strength and gas flow affect the precipitation rate.

After the precipitation rate parameter has been determined from resistivity and other studies, the Deutsch-Anderson equation or a modified

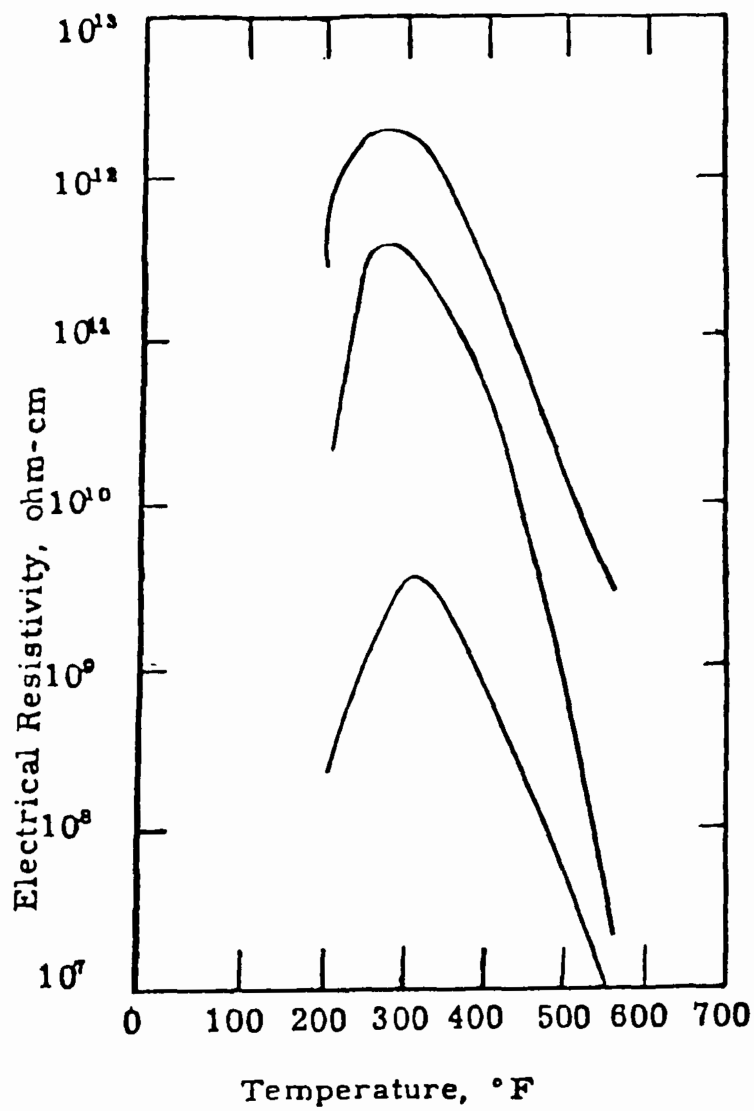


Figure 4.1-14. Electrical resistivity of fly ash from three MSW incinerators and boilers.[44]

TABLE 4.1-1. ELECTRICAL RESISTIVITY DATA FOR NONFOSSIL FUEL FIRED BOILERS[9,42,45-49]

Nonfossil fuel	Auxiliary fuel	NFF-% fuel input	Temperature,°F	Resistivity, ohm·cm
Bark	None	100	--	10^6 - 10^7
Bark[a]	None	100	--	1.7 - 10^5
Bark[b]	None	100	--	9.6 x 10^9
Bark	None	100	--	1.4 x 10^6
Bark	None	100	--	9.6 x 10^5
Bark	None	100	--	8.4 x 10^7
Bark	LSC[c]	~50	212-572	10^{10}- 10^{13}
MSW	None	100	300-400°F[d]	10^6 - 5 x 10^{12}
MSW	None	100	--	3 x 10^8[e] /5 x 10^6[f]
RDF	LSC	8	--	2 x 10^{11}
RDF	LSC	10	--	5.3 x 10^{10}
RDF	LSC	4-5	--	4.2 - 17 x 10^{10}
RDF	LSC	10	--	1.8 x 10^{11}
RDF	LSC	9-27	--	4-6 x 10^{11}
RDF	HSC[g]	~40	--	1.05 x 10^8

[a]Bark entering primary mechanical collector.

[b]Bark entering secondary collector.

[c]Low sulfur coal, % sulfur = 0.6 - 1.1%.

[d]Temperature range for maximum resistivity.

[e]Coarse material.

[f]Fine material.

[g]High sulfur coal, % sulfur = 4.15%.

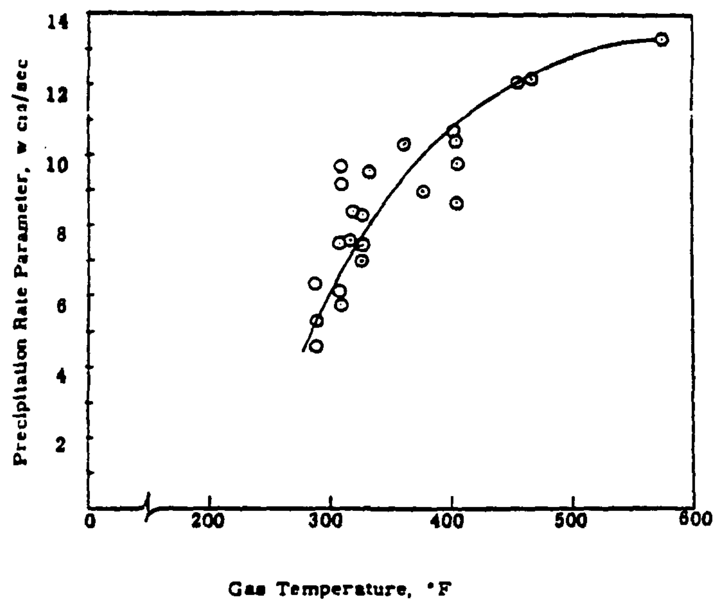


Figure 4.1-15. Variation in precipitation rate parameter with gas temperature in European and U.S. MSW incinerators and boilers.[51]

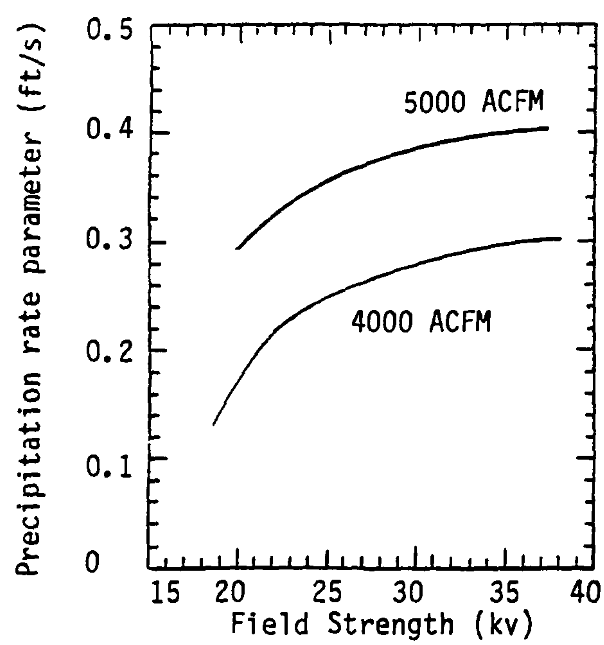


Figure 4.1-16. Effect of field strength on precipitation rate parameter by pilot ESP treating flue gas from boiler firing bark and low sulfur coal[47]

equation can be used to predict the SCA needed to attain desired particulate matter removals.

The relationship between collection efficiency and SCA is illustrated in Figures 4.1-17 and 4.1-18. Figure 4.1-17 shows the relationship between efficiency and SCA for removing fly ash from coal-fired boiler flue gas. Figure 4.1-18 shows the experimentally determined relationship between efficiency and SCA for removing fly ash from a bark/coal cofired boiler flue gas. Another boiler cofiring bark and low sulfur coal (25 percent bark) is designed to achieve 99 percent removal at an SCA of 60 $m^2/(m^3/s)$ (300 ft^2/1000 acfm).[53] Pilot tests of an ESP on a wood-fired boiler showed a removal efficiency of 90.6 percent at an SCA of 40 $m^2/(m^3s)$ (200 ft^2/1000 acfm).[42]

The actual collection area during ESP operation depends on the flue gas flow rate which, for a particular boiler, is dependent on boiler load. The operating SCA increases as boiler load decreases, provided all ESP fields remain charged. Thus, the ESP must be designed to have the desired SCA at maximum boiler load where the flue gas flow is the highest.

The configuration and type of electrodes used in an ESP directly influence ESP performance. The electrode plate spacing, height, and length all influence the electrostatic forces exerted on the flue gas particles and thus influence the collection efficiency. Proper design of the ESP electrodes assures adequate residence time to allow the particles to migrate to a collection electrode.

Another key design variable is proper determination of the rapping cycle. If the cycle is too short, material that collects on the plates will not be compacted enough to settle to the bottom of the precipitation chamber and will be reentrained. This reentrainment can be minimized by proper design of collecting electrodes and rappers, minimizing rapping and rapping only a small section of the total precipitator plate area at a time. If the time between rapping is too long, however, the material on the collecting plates will become too thick and collection efficiency will be reduced. In addition, the rapping cycles must account for the differences in the amount of particulate matter collected in different ESP sections. ESP's typically

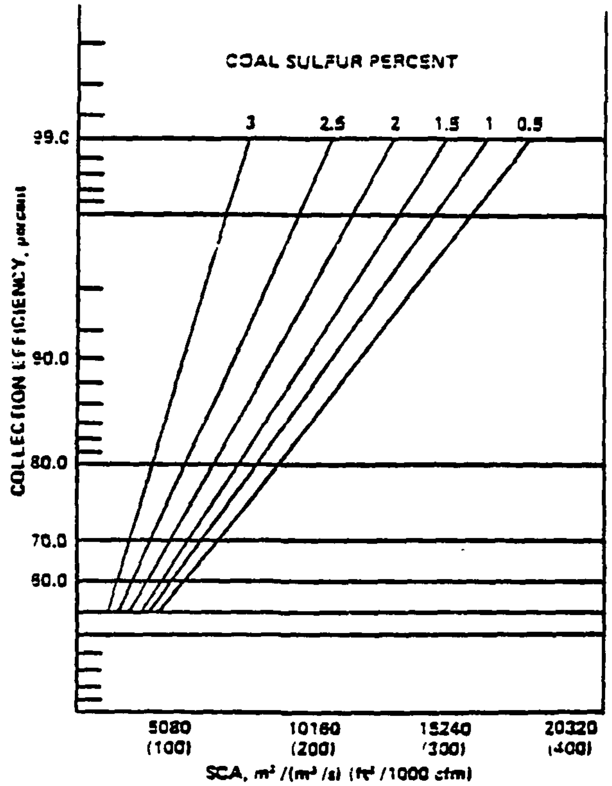


Figure 4.1-17. Relationship between collection efficiency and SCA for various coal sulfur contents.[52]

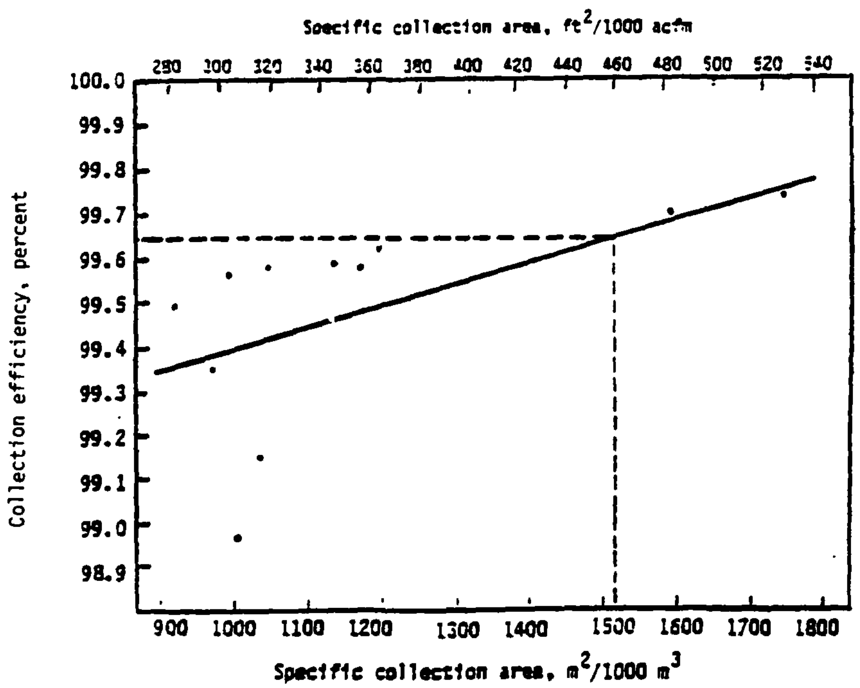


Figure 4.1-18. Pilot ESP particulate matter removal versus specific collection area for boiler firing bark and low sulfur coal.[47]

use multiple sections in series. The section which treats the flue gas first will collect more particles than subsequent sections. The rapping cycles must be adjusted to insure each section is rapped only when the collected material is the proper thickness. This necessitates more frequent cleaning cycles for the sections closest to the flue gas inlet.

Gas flow distribution also has a strong impact on ESP efficiency. Poor flow distribution between the collecting electrodes results in differing gas flow rates between each plate and therefore differing efficiencies for each section of the ESP. In addition, high velocities in the vicinity of hoppers and collecting electrodes can result in reentrainment of collected dust. Another distribution consideration is the avoidance of flue gas flow through certain areas of the ESP. The construction of an electrostatic precipitator is such that nonelectrified regions exist in the top of the precipitator where the electrical distribution, plate support and rapper systems are located. Similarly, portions of the collection hopper and the bottom of the electrode system contain nonelectrified regions. Particulate-laden gas streams flowing through these regions will not be subjected to collection forces and will tend to pass through the precipitator uncollected.[111] Gas flow distribution problems can be corrected by proper inlet design, such as adding straighteners, plitters, vanes, and diffusion plates to the duct work before the ESP and by internal baggles and flow restrictors.

The voltage applied to the ESP electrodes is also an important factor affecting performance. Proper voltage assures an adequate corona for charging the particles while minimizing problems of sparking.[112] The use of automatic power supply control is desirable in many applications because of the varying fly ash and flue gas properties brought on by varying boiler loads and fuel properties. Automatic controls allow the ESP to respond more effectively to these changes by reducing sparking and current loss.[64]

4.1.5 Gravel-bed and Electrostatic Gravel-bed Filtration

4.1.5.1 Process Description.[54] Gravel-bed and electrostatic gravel-bed filters remove particulate matter from gas streams in a dry form using a moving bed of filter media. Electrostatic filters additionally feature an electrically-charged grid within the gravel bed to augment collection by impaction. A typical electrostatic gravel-bed filter is shown in Figure 4.1-19.

The gravel-bed filter or electrostatic gravel-bed filter consists of two concentric louvered cylindrical tubes contained in a cylindrical vessel. The annular space between the tubes is filled with pea-sized gravel media. Particulate-laden gas enters the filter through breeching and is distributed to the filter face by a plenum section formed by the outer louvered cylinder and the vessel wall. Particulate matter is removed from the gas stream by impaction with the media. The PM-laden media exits the bottom of the gravel-bed vessel and is pneumatically conveyed to a de-entrainment vessel through a vertical lift pipe. The particulate matter is removed from the gravel media by the abrasion of media as it is conveyed up the lift pipe, by the scrubbing action of the air as it lifts the media, and by a rattler section in the de-entrainment vessel. The gravel media falls from the conveyor air stream by gravity and is returned to the filter bed. The separated PM is air conveyed to a storage silo where it is removed from the air stream by fabric filtration.

4.1.5.2 Development Status and Applicability to Nonfossil Fuel Fired Boilers. The first gravel-bed filter was installed on a wood-fired boiler in 1974. About 18 gravel-bed filters are now operating on wood-fired boilers. The first electrostatic gravel-bed was a retrofit of the first gravel-bed in 1978. Eight electrostatic gravel-bed filters are currently in operation on nonfossil fuel fired boilers. The fuels that electrostatic gravel-bed filters have been applied to include MSW, salt-laden wood, wood, and wood/coal and wood/oil mixtures.[113] Electrostatic gravel bed filters should also be applicable to bagasse- and RDF- fired boilers. New installations will almost certainly feature the electrically-charged grid because of its enhanced particulate removal efficiency. The enhanced removal due to the applied grid voltage is illustrated in Figure 4.1-20.

4.1.5.3 Factors Affecting Performance. Very little data are available to assess the factors affecting the performance of gravel-bed filters and

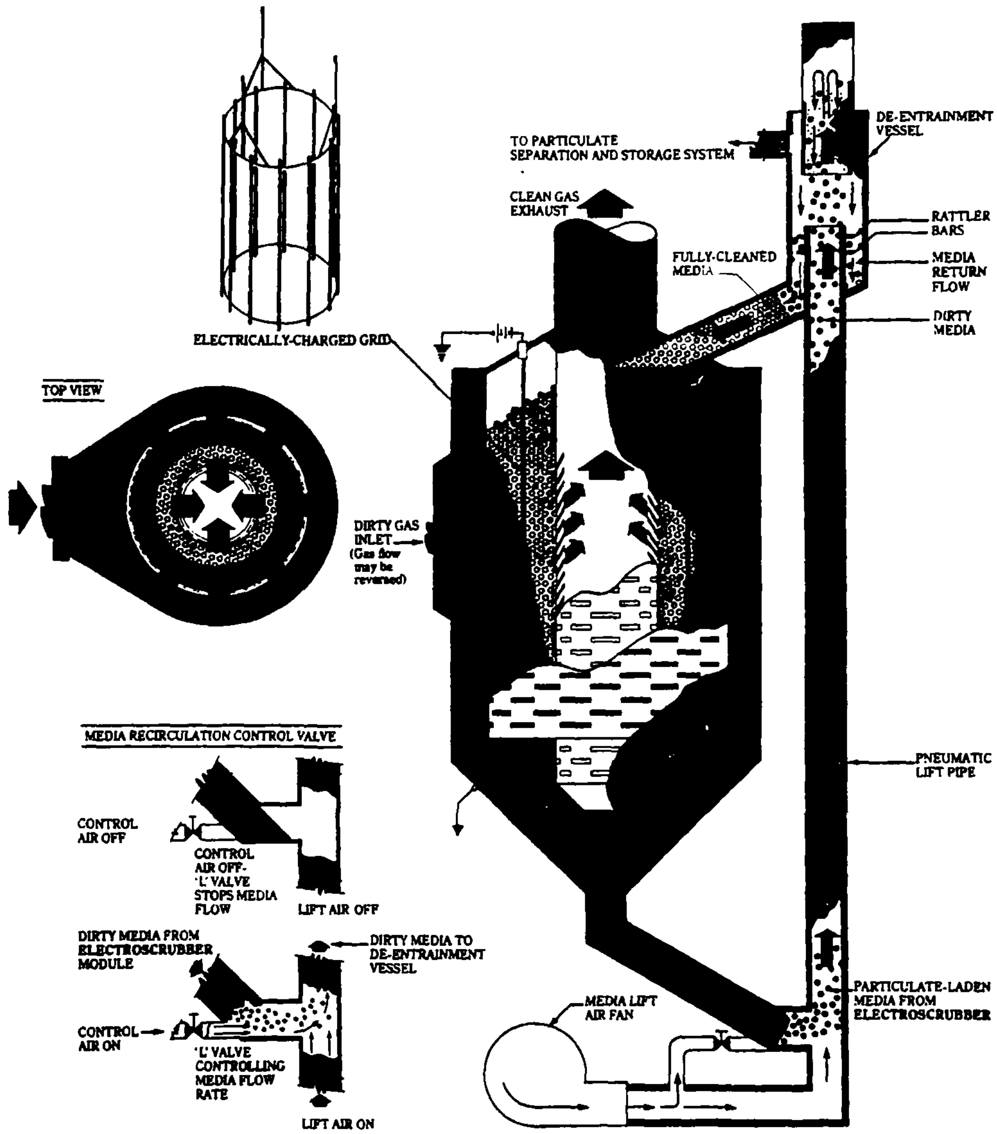


Figure 4.1-19. Schematic of an Electroscrubber™, electrostatic granular filter (Courtesy of Combustion Power Company, Inc.)[54]

electrostatic gravel-bed filters. The principal factors affecting performance are:

- the grid voltage
- the particle size of the particulate matter
- the air/media ratio
- the pressure drop across the media
- the extent of particulate separation from the spent media.

The effects of the first two factors are shown in Figure 4.1-20. Particle collection efficiency decreases with decreasing particle size and decreasing grid voltage. Based on theoretical considerations and on data for other PM control devices, particle collection efficiency should increase with decreasing air/media ratios and increasing gas-phase pressure drop. Specific data demonstrating these effects for gravel-bed and electrostatic gravel-bed filters are unavailable.

4.1.6 Performance of Particulate Matter Control Techniques

This section presents emission test data substantiating the performance of particulate matter control techniques. Only data obtained by approved EPA test methods and meeting established criteria for acceptability are presented to substantiate control technique performance. A more detailed discussion of each test shown is presented in Appendix C. Criteria for determining the acceptability of test data are also presented in Appendix C.

The nonmenclature used to identify the tests consists of two letters followed by a number. The two letters identify the facility. The number identifies the test performed at the facility. Tests performed at the same facility on different boilers or at different locations (i.e. before and after a wet scrubber) on the same boiler have the same two letter designator but followed by different numbers. The first letter of the two letter designator also specifies the fuel type. These are as follows:

- A or B indicates wood-fired or wood/fossil fuel cofired
- D indicates bagasse-fired
- F indicates MSW-fired
- H indicates RDF-fired or RDF/coal cofired

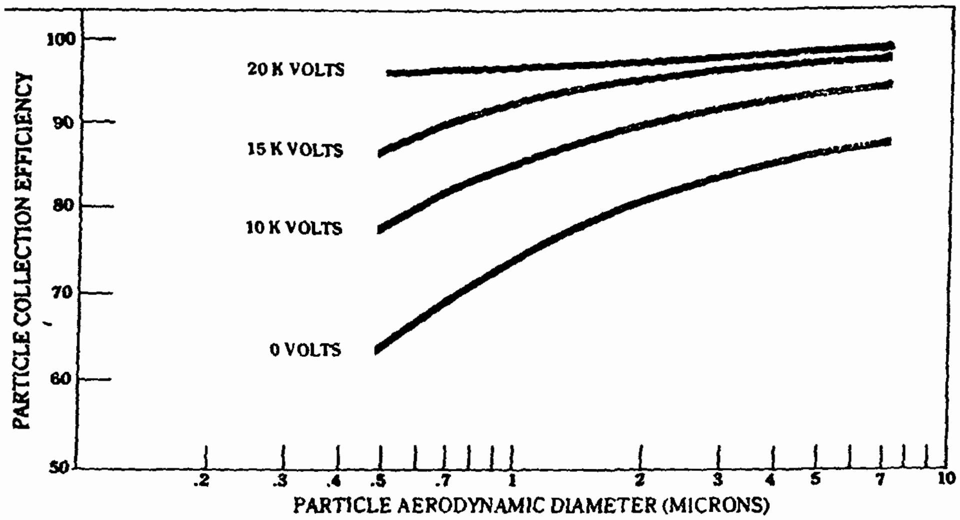


Figure 4.1-20. Fractional collection efficiency curves for the Electroscrubber™, electrostatic granular filter (Courtesy of Combustion Power Company, Inc.)[54]

Each emission test consists of one or more test runs with the majority of the tests presented consisting of three test runs. An arithmetic average of the test runs is also presented for each test.

Also presented with the emission data are available data on the boiler, control devices, and the fuel composition. As discussed in Chapter 3 several variables can affect uncontrolled emissions, and hence controlled emissions. These factors are boiler type, fuel type, and boiler operation. Information on these factors is presented for each test. All of the tests indicate the boiler type and as much information as is available on the fuel. Boiler operation factors shown include load factor (percent of rated capacity) and oxygen content of the flue gas.

A NFFB with an excess air level of 50 percent would have about a 7 percent oxygen content in the flue gas assuming no leakage of air into the flue gas. At 100 percent excess air the oxygen content would be about 10.5 percent. The oxygen contents shown in the figures provide a rough basis of comparison of the amounts of excess air present during testing. The comparisons are rough since the measured oxygen concentrations do not distinguish between excess air to the furnace and air leakage into the flue gas after the furnace.

This section presents test data on different control devices which were designed to achieve varying emission levels. Particulate matter control techniques representing the most efficient controls for each fuel type are presented in Section 4.5.

4.1.6.1 Performance of Particulate Matter Control Techniques on Wood-Fired and Wood/Fossil Fuel Cofired Boilers. This section presents the available performance data on particulate matter emission controls applied to boilers firing wood or cofiring wood and fossil fuels.

The most common type of wood-fired boiler is the spreader stoker, and most of the available data shown are for this boiler type. However, data for fluidized bed, fuel cell, Dutch oven, and firetube boilers controlled by mechanical collectors are also included.

Data on wood fuels of various ash and moisture contents and fuel size are shown. The fuels burned during the tests range from sanderdust, sawdust, and bark, to hog fuel. The moisture contents vary from 6 percent for kiln dried wood up to 65 percent for bark.

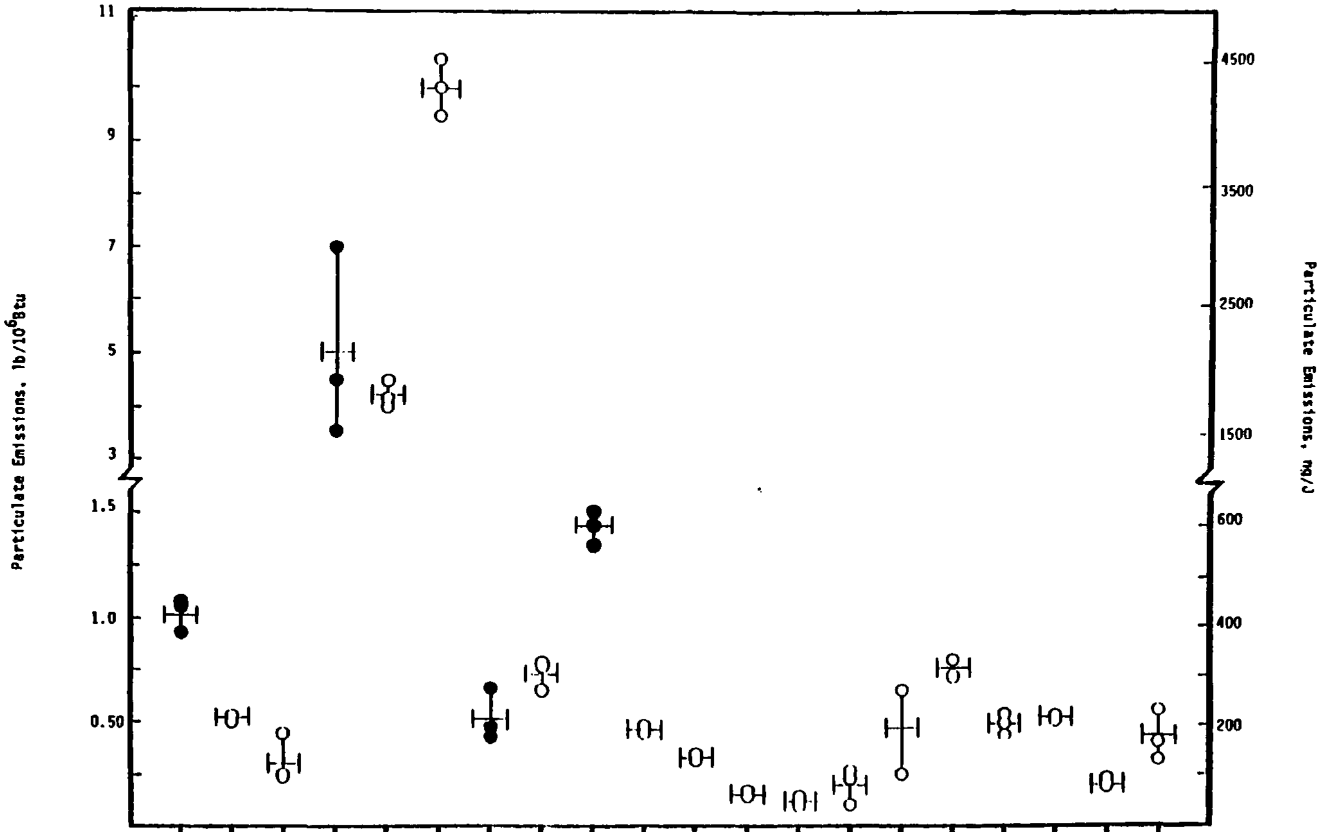
4.1.6.1.1 Performance of Mechanical Collectors on Wood-fired and Wood/Fossil Fuel Cofired Boilers. Figure 4.1-21 shows the available test data for mechanical collectors applied to wood-fired and wood/coal cofired boilers. The emission rates range from 4500 ng/J (10.5 $lb/10^6Btu$) down to less than 86 ng/J (0.20 $lb/10^6Btu$).

The highest emissions are shown by the pulverized coal (PC) boiler (test BF1) which fires bark and sawdust in suspension in addition to coal. This PC boiler is not typical of boilers firing wood 100 percent in suspension. Emissions from a representative small wood-fired suspension boiler are presented in test AS1. The lowest emissions are shown by the fuel cell boilers shown in tests AP1 and AO1. (The effect of boiler type on uncontrolled emissions is discussed in Chapter 3).

The spreader stoker fired boilers show widely varying emission rates. This could be partly due to varying fuel characteristics, but is probably mainly a function of boiler operation and maintenance. If the mechanical collector design limits are exceeded due to improper boiler operation or if the mechanical collector is not properly maintained the efficiency will drop will below design levels. For tests BD1 through BC1 (except for test AM1) the mechanical collector is used as a precleaning device.

Tests AX1 through BM1 were performed on small firetube boilers. These boilers are located in facilities which process kiln dried wood (such as furniture producers). As a result, the wood fuels fired in these boilers have moisture and ash contents lower than the other wood- fired boilers shown in Figure 4.1-21. The fact that these boilers fire a relatively clean dry fuel could account for the lower emissions generally shown by these boilers, even though they were generally operated at high excess air levels (as shown by the high flue gas oxygen contents). Test AM1 was performed on a watertube spreader stoker also firing clean kiln dried wood.

The firetube boilers shown in Figure 4.1-21 generally use a "drop chute" to feed wood dust to the grate while the larger pieces of wood fuel are manually stoked. However, as discussed in Chapter 3, firetube boilers



Test #	BD1	AM1	AR1	AK1	BH1	BF1	BE1	BL1	RC1	AL1	AN1	AP1	AO1	AX1	RK1	AS1	AY1	AU1	BM1	BN1
Boiler #	-	-	-	2	4/5[c]	-	11	-	1,2,3[d]	-	-	-	-	-	-	-	-	-	-	-
Boiler Type	SS	SS	SS	SS	PC/SS	PC	SS	OF	DO	FB	FB	FC	FC	FT	FT	FT[j]	FT	FT	FT	FT
Design Capacity - (10^3 lb/hr steam)	25	60	70	135	140/200	350	400	10	3x50	15	36	20	25	2.6	3.4	5.2	6.0	7.4	8.2	26
Nonfossil Fuel Type	B	W,S,SD	HF,SD1	B,S	-/B	B,S	HF	B,S	SHF	B,S	B,S	S,B	HF	W,SD	W,SD	W	W,SD	W	W	W
% of Heat Input[f]	100	100	100	100	-/80	25	100	100	100	100	100	100	100	81	100	100	100	100	91	100
% Ash (dry)	5.1	-	-	1.7	-/5.9	-	9.4[k]	-	3.4	-	-	-	-	-	-	-	-	-	-	-
% Moisture	47	6-7[g]	45[g]	45	-/28	-	56[k]	-	57	-	45[g]	47[g]	-	-	-	-	-	-	-	-
Other fuel	-	-	-	-	LSC/LSC[h]	Coal	-	-	-	-	-	-	-	LSO	-	-	-	-	Coal	-
Load factor - %[f]	75	15	79	94	84/46	94	96	42	91[h]	92	78	35	80	86	40	60	53	124	102	50
% O_2 in flue gas[f]	10.2	18.0	8.2	14.5	12.7	9.0	10.1	13.2	11.2	11.8	10.4	10.9	10.5	17.8	18.6	8.7	18.8	14.6	14.4	16.1
Control Device	MC	MC	MC	MC	MC/MC	MC	2xMC[i]	MC	MC	MC	MC	MC	MC	MC	MC	MC	MC	MC	MC	MC
Fly Ash Reinjection	N	N	Y	Y	N/Y	N	Y	N	N	N	N	N	N	N	N	Y	N	N	Y	Y
Sand Classification	N	N	Y	Y	N/N	N	Y	N	N	N	N	N	N	N	N	N	N	N	N	N

Figure 4.1-21. Particulate Emissions from Wood-Fired and Wood/Fossil Fuel Cofired Boilers Controlled by Mechanical Collectors.[a,b]

Footnotes for Figure 4.1-21.

[a]All data were obtained by EPA Method 5 and meet established criteria for acceptability. The key for the data is:

SS - spreader stoker
PC - pulverized coal
OF - overfeed stoker
DO - dutch oven
FB - fluidized bed
FC - fuel cell
FT - firetube boilers. The firing methods for the small firetube boilers shown here generally consist of a "drop chute" for wood dust with the large fuel pieces manually stoked. Firetube boilers can also be fired using the same firing methods as watertube boilers.
W - wood scraps
S - shavings or sawdust
SD - sanderdust
SDI - sanderdust burned using a separate sanderdust injector system
B - bark
HF - hog fuel (wood/bark mixture)
SHF - salt-laden hog fuel
LSC - low sulfur coal
LSO - low sulfur distillate oil
MC - mechanical collector
Y - yes
N - no
O - EPA-5 test data acquired in industry tests
● - EPA-5 test data acquired in EPA tests
⊢⊣ - average

[b]More detailed information on the emission test data and the data sources may be found in Appendix C.

[c]Two boilers were tested at this facility. The flue gases pass through individual mechanical collectors and are then combined in a single duct. This duct is then split prior to entering two ESPs. The data shown is the weighted average of samples taken from the two ducts prior to the ESPs.

[d]The flue gases from boilers 1,2, and 3 pass through individual mechanical collectors. They are then combined in a single duct prior to entering a baghouse. This test was performed on the single duct prior to the baghouse.

[e]An analysis of the coal showed the following composition: Moisture - 3.2%; Ash (dry) - 17.7%; Sulfur (dry) - 0.56%.

[f]Average value during testing.

[g]These data did not come from an analysis done during emission testing. They were obtained from industry sources and are representative of the typical fuel burned at this facility.

[h]Based on the combined steam flow of all three boilers.

[i]Two mechanical collectors in series.

[j]This boiler fires all of the wood in suspension. The wood fuel is finely ground until it is similar to sanderdust.

[k]At this facility char from the first stage of the mechanical collector is slurried and separated by screens into large and small fractions. The large char fraction is mixed with the hog fuel. These values represent an analysis of the mixture of char and hog fuel.

could also use the same firing methods as the watertube boilers shown. While the emission rate can be affected by the firing method, the boiler tube design has little effect on emissions.

One test is available on a dual mechanical collector used as a precleaner applied to a wood-fired spreader stoker boiler (BE1). This test showed average emissions of 215 ng/J (0.5 $lb/10^6$ Btu).

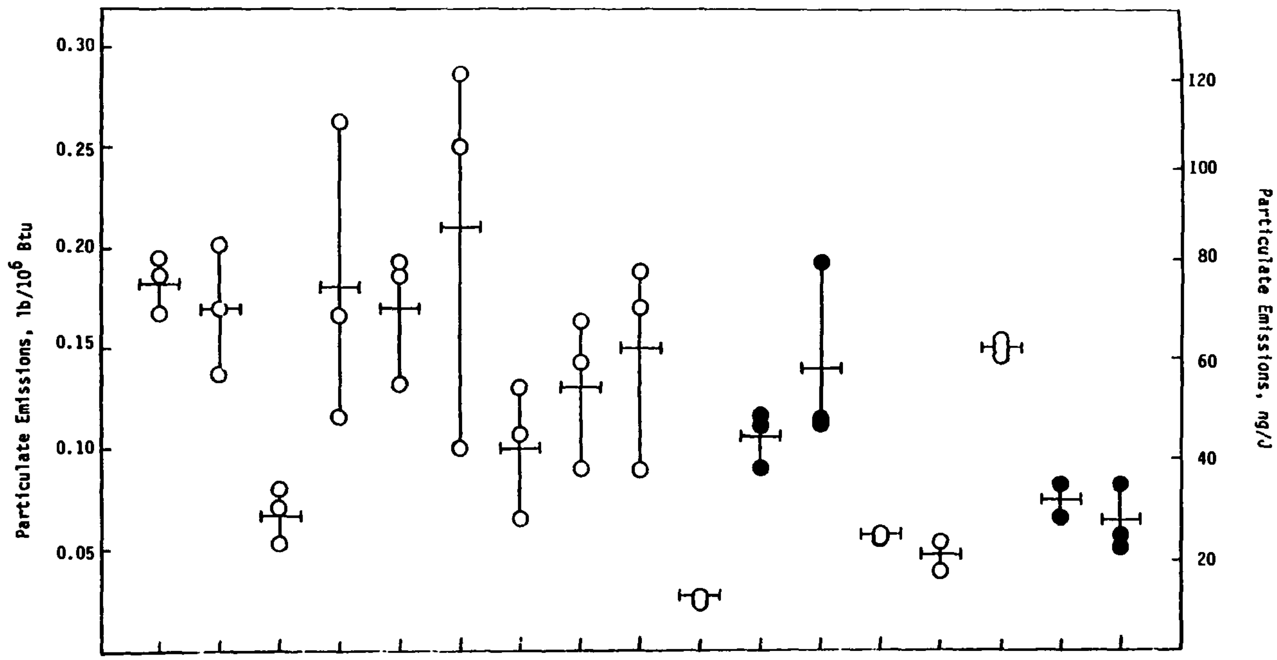
Based on the limited data available it is not possible to determine the actual long term performance that would be expected for dual mechanical collectors. The data shown for dual mechanical collectors in Figure 4.1-21 falls within the range of performance for single stage mechanical collectors also shown in Figure 4.1-21.

4.1.6.1.2 Performance of Wet Scrubbers on Wood-fired and Wood/Fossil Fuel Cofired Boilers. Figure 4.1-22 shows the available emission test data for wood-fired and wood/fossil fuel cofired boilers controlled with wet scrubbers. The scrubbers in Tests AD1 through BF2 were either impingement scrubbers or fixed throat venturi scrubbers. Tests AJ2 through AK3 were on adjustable throat venturi scrubbers. The gas phase pressure drops for these scrubbers ranged from 1.5 to 6.5 kPa (6 to 26 in. w.c.) and the emission levels were 12 to 91 ng/J (0.03 to 0.21 $lb/10^6$ Btu). All the scrubbers have a mechanical collector upstream for precleaning and sometimes for fly ash reinjection also. Only the scrubber at Plant AA has a mist eliminator.

These emission data generally show decreasing emissions as the scrubber pressure drop increases. However, some of the tests showed significant deviations from the values expected at the scrubber pressure drop shown. These tests are discussed in the following paragraphs.

Two tests performed on the lower pressure drop scrubbers (AB2 and BF2) show significantly lower emissions that would be expected. For Test AB2 this is due to the low emissions from the mechanical collector to the scrubber inlet (shown in Figure 4.1-21, Test AB1) compared to other spreader stoker wood-fired boilers. Some of the factors which could contribute to these low emissions are:

- Overall fuel moisture content is 45 percent. This is a lower moisture content than is found in many wood fuels.



Test #	AD1	AC2	AB2	AC1	AG1	AI1	AF1	AE1	AH1	BF2	AJ2	AJ4	AJ5	AA1	BG1	AK2	AK3
Boiler Type	SS	SS	SS	SS	SS	SS	SS	SS	SS	PC	SS	SS	SS	SS	SS	SS	SS
Design Capacity- (10^3 lb/hr steam)	40	55	70	37/37[c]	110	110	120	120	140	350	110	110	110	150	200	135	135
Nonfossil Fuel Type	B,W	B,W	HF,SDI	B,W	B,S,W	S,PWR	B,W	B,S	B,W	B,S	B,S	B,S	B,S	HF	SHF	B,S	B,S
% Heat Input[f]	100	100	100	100	100	100	100	100	100	25	100	100	100	100	90	100	100
% Ash (dry)	-	-	-	-	-	-	-	-	-	-	2.2	1.9	-	2-8[d]	-	1.7	4.2
% Moisture	-	-	45[d]	-	-	-	-	-	-	-	48	50	-	60-65[d]	55[d]	45	45
Other Fuel	-	-	-	-	-	-	-	-	-	Coal	-	-	-	-	HSO	-	-
Load Factor - %[f]	73	47	79	63[e]	103	86	72	85	65	94	91	95	91	95	75	94	100
% O_2 in flue gas[f]	11.5	12.5	9.5	11.9	7.7	10.9	7.6	9.1	8.2	9.0	14.0	14.9	8.8	7.3	6.8	14.5	11.8
Control Device	MC/WS	MC/WS	MC/WS	MC/WS	MC/WS	MC/WS	MC/WS	MC/WS	MC/WS	MC/WS	MC/WS	MC/WS	MC/WS	MC/WS	MC/WS	MC/WS	MC/WS
Operating Parameter-ΔP[f] (in. w.c.)	6-8	6-8	6-8	6-8	6-8	6-8	6-8	6-8	6-8	9	8.0	13.5	15.2	18	19	20	26
Fly Ash Reinjection	Y	N	Y	N	Y	Y	Y	Y	Y	N	Y	Y	Y	Y	N	Y	Y
Sand Classification	N	N	Y	N	Y	Y	Y	Y	Y	N	Y	Y	Y	Y	N	Y	Y

Figure 4.1-22. Particulate Emissions from Wood-Fired and Wood/Fossil Fuel Cofired Boilers Controlled by Wet Scrubbers.[a,b]

Footnotes to Figure 4.1-22:

[a]All data were obtained by EPA Method 5 and meet established criteria for acceptability. The key for the data is:

- SS - spreader stoker
- PC - pulverized coal
- B - bark
- W - wood scraps
- HF - hog fuel (wood/bark mixture)
- SHF - salt-laden hog fuel
- SDI - sanderdust which is burned using a separate sanderdust injector system
- PWR - pulverized wood residue
- S - sawdust or shavings
- HSO - high sulfur residual oil
- MC - mechanical collector
- WS - wet scrubber
- P - pressure drop
- Y - yes
- N - no
- O - EPA-5 data acquired in industry tests
- ● - EPA-5 data acquired in EPA tests
- ├┤ - average

[b]More detailed information on the emission test data and the data sources may be found in Appendix C.

[c]Two boilers which exhaust into a single wet scrubber.

[d]These data did not come from an analysis done during emission testing. They were obtained from industry sources and are representative of the typical fuel burned at this facility.

[e]Based on combined steam flow of both boilers.

[f]Average valve during testing.

- The excess air level is approximately 80 percent. Many of the other spreader stoker fired boilers tested had excess air levels well over 100 percent.
- The fine fuel particles are fed through a separate sanderdust injection system.
- The fuel at this facility is size classified and only oversize pieces are hogged. This increases the average fuel particle size.

A discussion of how these factors can reduce uncontrolled emissions can be found in Section 3.2.1.2.

Tests AJ2, AJ4, and AJ5 were on the same boiler and control system. Test AJ5 was performed to determine if the boiler was in compliance with the State emission regulation of 129 ng/J (0.3 lb/10^6 Btu). During this test the measured excess air level was 70 percent at the scrubber outlet. During Tests AJ2 and AJ4 the measured excess air levels at the scrubber outlet ranged from 150 to 300 percent. As discussed in Chapter 3, excess air levels higher than those required for good combustion can cause an increase in particulate emissions. In fact, the particulate emission simultaneously measured at the scrubber inlet during Tests AJ2 and AJ4 were higher than scrubber design levels on 4 of the 6 test runs.

Because of the high excess air, the emission levels in Tests AJ2 and AJ4 are higher than the levels expected from the boiler and control system when properly operated. There is no reason that excess air levels on a wood-fired boiler would have to be increased from 70 percent to 150 or 300 percent. Since these measurements were made at the same location, the affect of air leakage into the flue gas should not affect this comparison.

- Test BG1 shows significantly higher emissions than other wet scrubbers with similar pressure drops. This boiler fired salt-laden wood containing 0.4 percent salt (dry basis) in the fuel during this test. The results of the emission test showed that the particulate emitted from the wet scrubber contained 6 percent salt. However, other reported test data have shown a salt content of 50 percent or more in the particulate emissions from this scrubber. Salt particulate emissions have small particle sizes making them difficult to control efficiently with a scrubber. Therefore, the salt would contribute to the higher emissions.

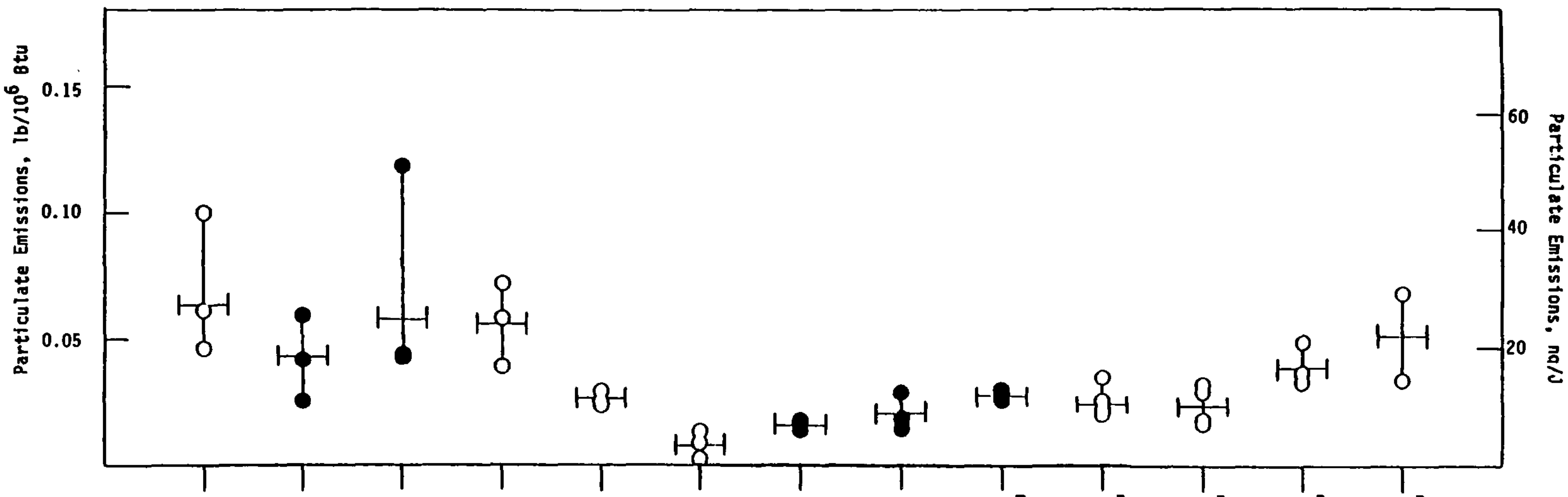
Another difference in this system compared to the other high pressure drop scrubbers (over 3.7 kPa) shown is the use of recycled scrubber water without a mist eliminator. High pressure drop scrubbers can entrain significant amounts of water in the exit flue gas. This water, which contains suspended PM, can evaporate in the stack releasing the PM back into the stack gas. Therefore, high pressure drop scrubbers should be equipped with mist eliminators. The other high pressure drop scrubbers shown in Figure 4.1-21 (except at Plant AA) use once through scrubber water, which reduces the particulate matter carry over by reducing this solid content of the scrubber liquor. The scrubber at Plant AA used recycled scrubber water, but this scurbber has a mist eliminator.

4.1.6.1.3 Performance of ESPs, Fabric Filters, and EGBs on Wood-Fired and Wood/Fossil Fuel Cofired Boilers. Figure 4.1-23 shows the available emission test data for wood-fired and wood/fossil fuel cofired boilers controlled by ESPs, fabric filters, or EGBs. All of these tests showed emission levels below 34 ng/J (0.08 lb/10^6 Btu).

Five of these emission tests were performed on boilers firing wood or mixtures of wood and coal controlled by ESPs. These tests generally show decreasing emissions as the SCA of the ESP increases.

Two tests with fabric filters used for particulate control are shown. Average emission levels for both facilities are about 9 ng/J (.02 lb/10^6Btu) with A/Cs ranging from 0.9 - 1.1 m/min (3.0 - 3.7 ft/min). Facility BC fires a salt-laden wood fuel which produces a salt particulate.

Two tests were performed on an EGB. This EGB has 3 modules. Each module cleans one third of the total flue gas and has its own stack. The first test (BE2) was performed by EPA. The data shown are the weighted average of the three stacks. This test was run under typical operating conditions at this facility. The second test was performed by the boiler operator and consisted of 15 test runs under a range of operating conditions. The data shown are the emissions from the outlet of Module 3 of



Test #	BA1	BI1	BH6	BB1	BJ1	BH2	BD2	BC2	BE2[m]	BE3[n]	BE4[n]	BE5[n]	BE6[n]
Boiler #	-	7/8[c]	4/5[d]	-	-	4/5[d]	-	1,2,3[j]	11	11	11	11	11
Boiler Type	SS	SS/SS	PC/SS	SS	SS	PC/SS	SS	DO	SS	SS	SS	SS	SS
Design Capacity (10^3 lb/hr steam)	110	240/325	140/200	450	600	140/200	25	3x50	400	400	400	400	400
Nonfossil Fuel Type	B,SD	B/B	-/B	HF	B,S	-/B	B	SHF	HF	HF	HF	HF	HF
% Heat Input[h]	100	25/25	-/100	100	64	-/80	100	100	100	100	100	100	100
% Ash (dry)	-	3.4	4.4	4.8[i]	-	-/5.9	5.1	3.4	9.4[k]	3.8	3.8	4.8	4.8
% Moisture	-	46	42	42[i]	-	-/28	47	57	56[k]	49	50	58	59
Other Fuel	-	LSC/LSC[e]	LSC/[f]-	-	HSO	LSC/LSC[g]	-	-	-	-	-	-	-
Load Factor - %[h]	66	87/87	48/88	69	76	84/46	75	91	96	101	116	95	107
% O_2 in flue gas[h]	9.4	10.2	12.5	6.3	6.2	9.9	9.9	10.7	9.6	7.9	7.2	8.1	8.7
Control Device	MC/ESP	MC/ESP	MC/ESP	MC/ESP	MC/ESP	MC/ESP	MC/FF	MC/FF	MC/EGB	MC/EGB	MC/EGB	MC/EGB	MC/EGB
Operating Parameter[h,i]	230	320	452	453	456	600	3.66	2.98	6.0	3.4	4.0	5.6	7.1
Design Parameter[i]	177	296	460	298	356	460	4.10	3.64	-	-	-	-	-
Fly Ash Reinjection	Y	Y	N/Y	Y	Y	N/Y	N	N	Y	Y	N	Y	N
Sand Classification	N	N	N/N	Y	Y	N/N	N	N	Y	Y	N	Y	N

Figure 4.1-23. Particulate Emissions from Wood-Fired and Wood/Fossil Fuel Cofired Boilers Controlled by ESPs, Fabric Filters, and EGBs.[a,b]

Footnotes for Figure 4.1-23.

[a]All data were obtained by EPA Method 5 and meet established criteria for acceptability. The key for the data is:

SS - spreader stoker
PC - pulverized coal
DO - dutch oven
B - bark
S - sawdust or shavings
SD - sanderdust
HF - hog fuel (wood/bark mixture)
SHF - salt-laden hog fuel
LSC - low sulfur coal
HSO - high sulfur residual oil
MC - mechanical collector
ESP - electrostatic precipitator
FF - fabric filter
EGB - electrostatic gravel bed filter
Y - yes
N - no
O - EPA-5 data acquired in industry tests
● - EPA-5 data acquired in EPA tests
|—| - average

[b]More detailed information on the emission test data and the data sources may be found in Appendix C.

[c]The flue gas from boilers 7 and 8 passes through individual mechanical collectors. It is then combined into a single duct and then split to enter a two chamber ESP with two stacks. The emission levels shown are the weighted average of both stacks.

[d]The flue gas from boilers 4 and 5 passes through individual mechanical collectors. It is then combined into a single duct and then split to enter two separate ESPs in parallel. The emission levels shown are the weighted average of both stacks.

[e]The analysis of the coal showed the following composition: Moisture - 5.5%; ash (dry) - 12.4%; sulfur (dry) - 0.86%.

[f]The analysis of the coal showed the following composition: Mositure 3.9%; ash (dry) - 7.1%; sulfur (dry) - 0.7%.

[g]The analysis of the coal showed the following composition: Moistore - 3.2%; ash (dry) - 17.7%; sulfur (dry) - 0.56%.

[h]Average value during testing.

[i]For ESPs this value is specific collection area in ft^2/1000 acfm; for fabric filters this value is air to cloth ratio in ft/min; for the EGB this value is pressure drop in inches of water.

[j]The flue gas from boilers 1,2 and 3 passes through individual mechanical collectors. It is then combined into a single duct prior to entering the fabric filter.

[k]At this facility char from the first stage of the mechanical collector is slurried and separated by screens into large and small fractions. The large char fraction is mixed with the hog fuel. These values represent an analysis of the mixture of char and hog fuel.

[l]These data did not come from an analysis done during emission testing. They were obtained from industry sources and are representative of the typical fuel burned at this facility.

[m]The EGB has three modules, each of which cleans one-third of the flue gas. Each module has a separate stack. The emission levels shown are the weighted average of all three stacks.

[n]Emissions are from the outlet of module 3 of the EGB.

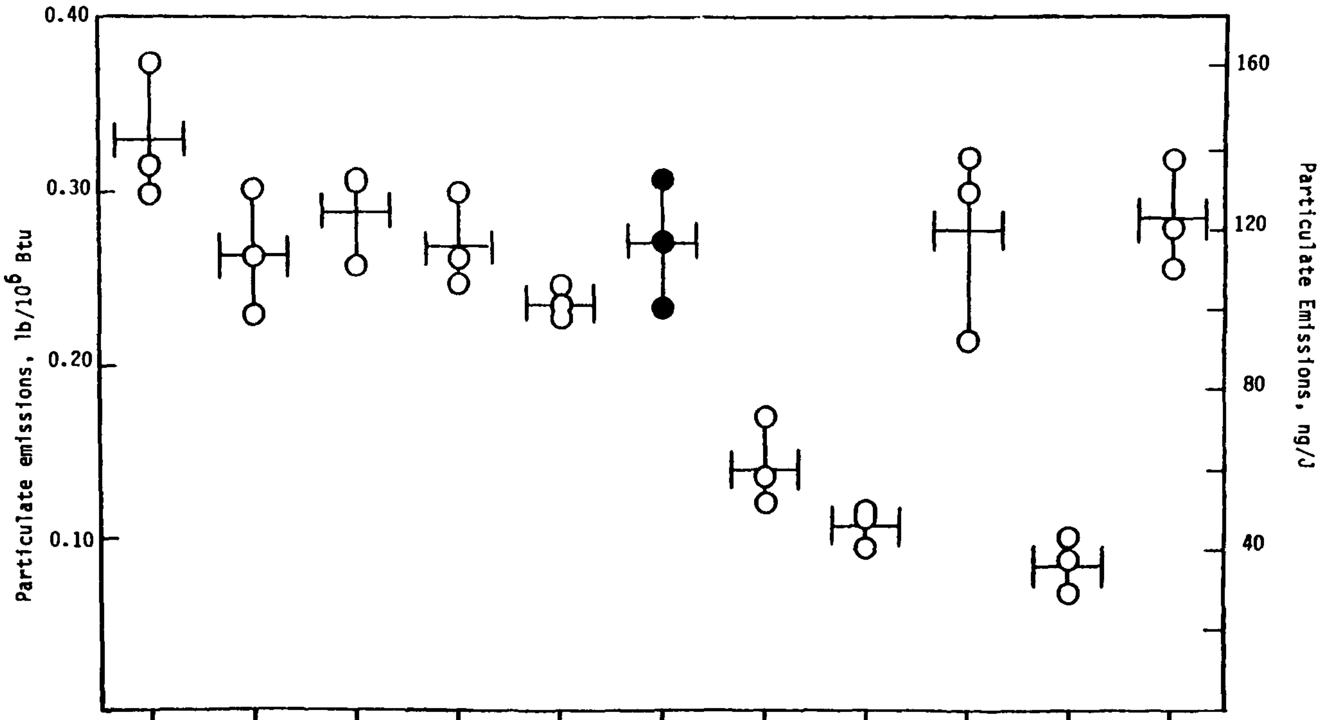
the EGB only. The 15 test runs are grouped into 4 different sets. These sets are as follows:

- Set BE3 consists of test runs 1,2,5,7 and 9. In this set "good" hog fuel was fired and flyash was reinjected.
- Set BE4 consists of test runs 3,4,8 and 15. "Good" hog fuel was fired and flyash was not reinjected.
- Set BE5 consists of test runs 10,11 and 13. "Poor" hog fuel was fired and flyash was reinjected.
- Set BE6 consists of test runs 12 and 14. "Poor" hog fuel was fired and flyash was not reinjected.

For these tests the definition of "good" hog fuel is hog fuel with moisture content of less than 55 percent. Hog fuel with a moisture content of 55 percent or more is defined as "poor". Test run 6 was made with the electrostatic grid turned off. Since this is not part of normal operation, this test run was not shown. The emission rates shown by the EGB were comparable to those shown by ESPs and fabric filters.

4.1.6.2 Performance of Particulate Matter Control Techniques On Bagasse-Fired Boilers. Figure 4.1-24 shows the available performance data for bagasse-fired boilers controlled by wet scrubbers and mechanical collectors. These two types of control devices are the only types in use on bagasse-fired boilers.

The data for bagasse-fired boilers controlled by wet scrubbers show average emissions which range from 140 ng/J (0.33 $lb/10^6$ Btu) down to 36 ng/J (0.07 $lb/10^6$ Btu). The lowest emissions are shown in test DC1. This is the only scrubber facility with both a cyclone for precleaning and a mist eliminator. This wet scrubber is an ejector venturi design. Though the flue gas pressure drop is only 0.5 kPa (2 in. w.c.), the scrubbing liquid pressure drop is higher than for a typical venturi scrubber. This results in better atomization of the water droplets and increased scrubber efficiency. This scrubber would be equivalent to "standard" venturi scrubber with a gas phase pressure drop of 1.5 kPa (6 in. w.c.).[108,109] Plants DC1 and DD1 also fire a bagasse with a lower moisture content than the other facilities shown.



Test #	DA1	DA2	DE1	DE2	DE3	DH2	DH1	DG1	DF1	DC1	DD1
Boiler #	3	4	6	12	14	2	5	5	2	-	-
Boiler Type	HS	HS	FC	SS	SS	SS	SS	SS	HS	SS	SS
Design Capacity - (10^3 lbs/hr steam)	125	125	125	150	150	150	200	160	125	312	288
Bagasse Characteristics-											
% Heat Input[c]	92	100	94	100	100	99	100	80	100	100	100
% Ash(dry)	-	-	-	-	-	1.8	-	-	-	3.0	-
% Moisture	-	-	-	-	-	58.4	-	-	-	48	48
Other fuel	HSO	-	HSO	-	-	HSO	-	HSO	-	-	-
Load Factor - %[c]	78	71	96	92	98	97	82	103	71	93	68
% O_2 in flue gas[c]	12.1	11.8	11.0	4.8	5.9	9.2	10.5	8.4	11.3	7.1	8.7
Control Device	2WS[d]	WS	WS	MC/WS	MC/WS	2WS[d]	WS	2WS[d]	2WS[d]	MC/WS	2xMC[e]
Operating Parameter - ΔP[c] (in. w.c.)	5-7	5-7	6	6	6	6	6	5-9	8-9	2[f]	2

Figure 4.1-24. Particulate Emissions from Bagasse-Fired Boilers Controlled by Wet Scrubbers and Mechanical Collectors.[a,b]

Footnotes to Figure 4.1-24:

[a]All of the data were obtained by EPA Method 5 and meet established criteria for acceptability. The key for the data is:

HS - horseshoe
FC - fuel cell
SS - spreader stoker
HSO - high sulfur residual oil
MC - mechanical collector
WS - wet scrubber
P - pressure drop
○ - EPA-5 test data aquired in industry tests
● - EPA-5 test data acquired in EPA tests
├─┤ - average

[b]More detailed information on the emission test data and the data sources may be found in Appendix C.

[c]Average value during testing. For all the wet scrubbers tested the scrubber pressure drop is assumed to be equal to the reported design value. The pressure drops were not actually measured during testing.

[d]Two wet scrubbers in parallel.

[e]Two mechanical collectors in series.

[f]This wet scrubber is an ejector venturi design, therefore the gas phase pressure drop is not a good indicator of scrubber efficiency. This scrubber would be approximately equiavalent to a "standard" venturi with a pressure drop of 1.5 kPa (6 inches w.c.).

The highest emissions are shown by Test DA1. This boiler uses two wet scrubbers in parallel for particulate matter control. When two wet scrubbers are used in parallel it is very difficult to maintain the same pressure drop in both scrubbers. The flue gas tends to take the path of least resistance through the scrubber with the lowest pressure drop. This effectively reduces the pressure drop for this system, therefore reducing the scrubber efficiency. A boiler identical to the boiler tested in Plants DA1 had its two parallel wet scrubbers replaced for this reason.[58] Test DA1 also shows the highest stack O_2 concentrations of any of these tests shown which may be indicative of high excess air rates in the boiler.

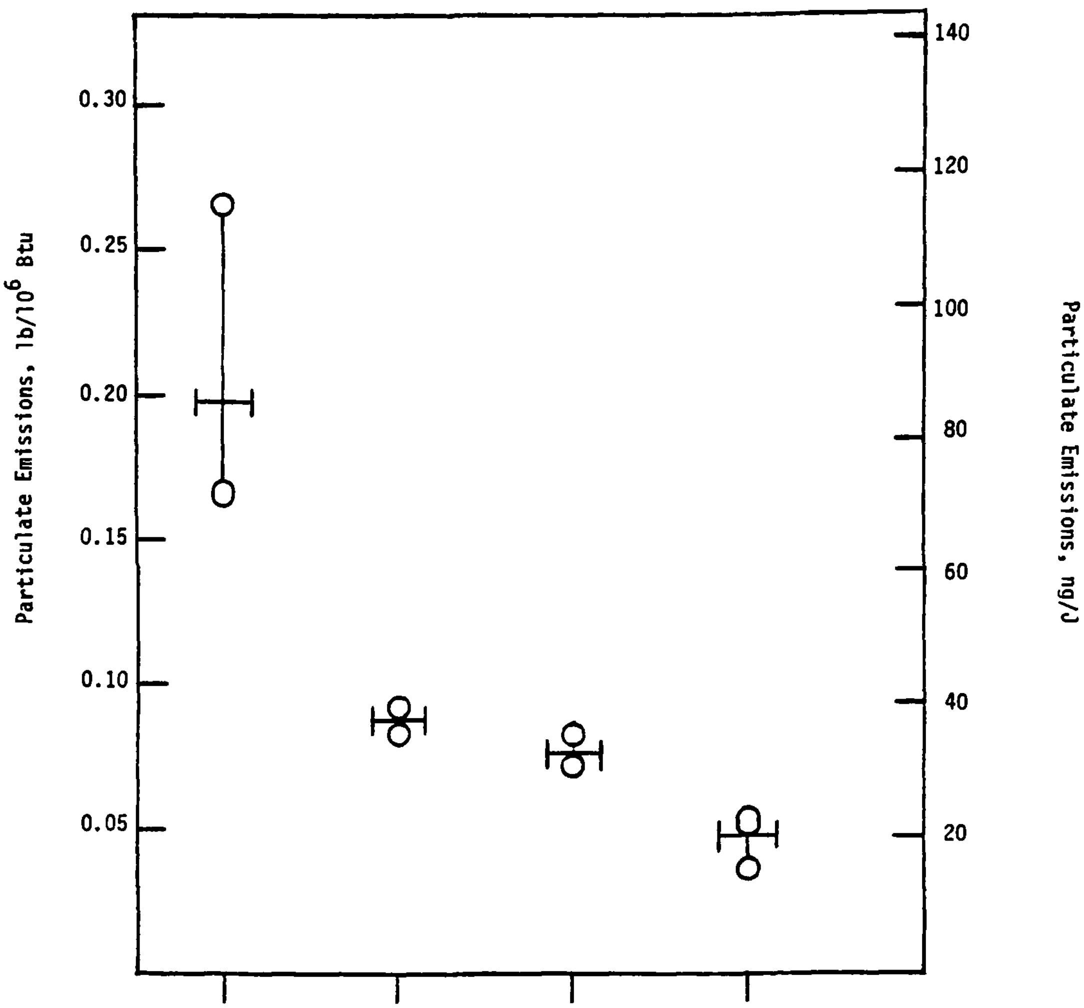
All of the tests except DA1 show average emissions below 130 ng/J (0.30 lb/10^6 Btu).

4.1.6.3 Performance of Particulate Matter Control Techniques on MSW-Fired Boilers. Figure 4.1-25 shows the available performance data for particulate matter (PM) controls applied to the large overfeed stoker type MSW-fired boiler described in Chapter 3. All of the facilities shown in Figure 4.1-25 use ESPs for PM control. The ESP is used almost exclusively on MSW-fired boilers presently in operation.[62]

These ESPs show a range of average emissions from 86 ng/J (0.2 lb/10^6 Btu) at an average specific collection area (SCA) of 28 $m^2/(m^3/s)$ (140 ft^2/1000 acfm) down to 21 ng/J (0.05 lb/10^6 Btu) at an average SCA of 100 $m^2/(m^3/s)$ (570 ft^2/1000 acfm).

The facilities are shown in order of increasing SCA during testing and follow the expected trend of decreasing emissions with increasing SCA with average emissions below 43 ng/J (0.1 lb/10^6 Btu) for the three facilities with SCAs larger than 48 $m^2/(m^3/s)$ (240 ft^2/1000 acfm).

4.1.6.4 Performance of Particulate Matter Control Techniques on RDF-fired Boilers. Figure 4.1-26 shows the available performance data for RDF/coal cofired boilers controlled with mechanical collectors. The units tested were spreader stokers firing RDF and coal at different fuel ratios and boiler operating conditions.



Test #	FA1	FC1	FE2	FB1
Boiler Type	OF	OF	OF	OF
Design Capacity (10^3 lbs/hr steam)	30	175/175[c]	110	135
Nonfossil Fuel Type	MSW	MSW	MSW	MSW
% Heat Input[d]	100	100	100	100
Load factor - %[d]	160[e]	80/88	79	77
% O_2 in flue gas[d]	12.9	9.8	9.4	9.2
Control Device	ESP	ESP	ESP	MC/ESP
Operating Parameter - SCA[d] (ft^2/1000 acfm)	139	243	278	573
Design Parameter - SCA (ft^2/1000 acfm)	126	209	154	316

Fiqure 4.1-25. Particulate Emissions from MSW-Fired Boilers Controlled by ESPs.[a,b]

Footnotes for Figure 4.1-25:

[a] Reported data were obtained with EPA Method 5 and meet established criteria for acceptability. The key for the data is:

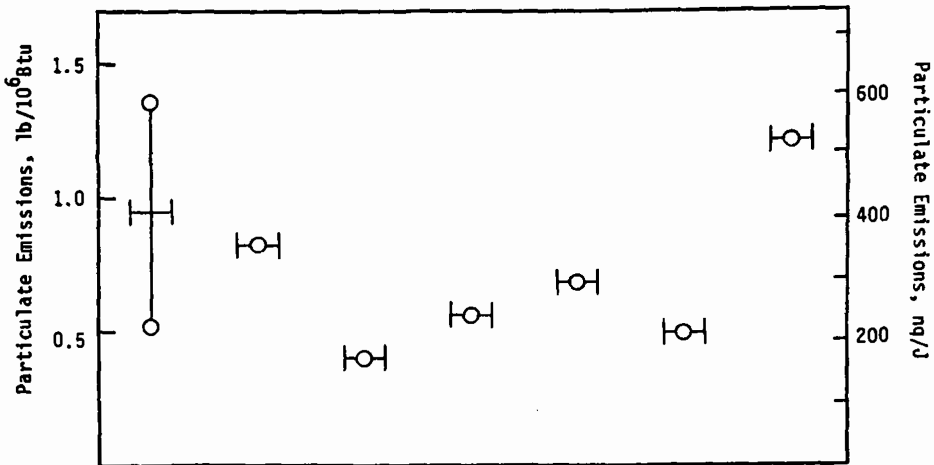
- OF - overfeed stoker
- MSW - municipal solid waste
- ESP - electrostatic precipitator
- MC - mechanical collector
- SCA - specific collection area
- O - EPA Method 5 data acquired in industry tests
- |—| - average

[b] More detailed information on the emission test data and the data sources may be found in Appendix C.

[c] Two boiler/ESPs are exhausted through a common stack; each boiler has a steam generating capacity of 175,000 lb/hr.

[d] Average value during testing.

[e] Boiler was being operated in excess of original rated capacity to determine if the required emission standard could be maintained at an increased capacity.



Test #	HD1	HD2	HD3	HE1	HE2	HE3	HE4
Boiler Type	SS	SS	SS	SS	SS	SS	SS
Design Capacity - (10^3 lb/hr steam)	45	45	45	35	35	35	35
Nonfossil Fuel Type	RDF	RDF	RDF	-	RDF	RDF	RDF
% Heat Input[c]	26	53	100	-	20	30	40
% Ash (dry)[d]	11.7	15.1	14.2	-	14.8	16.4	23.6
% Moisture[d]	5.4	5.1	5.9	-	18.4	17.4	11.9
Other fuel	Coal	Coal	Coal	Coal	Coal	Coal	Coal
Load Factor - %[c]	56	54	31	58	61	52	61
% O_2 in flue gas[c]	5.2	6.0	7.4	9.7	9.6	11.5	10.5
Control Device	MC	MC	MC	MC	MC	MC	MC

[a]All data were obtained by EPA Method 5 and meet established criteria for acceptability. The key for the data is:

SS - spreader stoker
RDF - refuse derived fuel
MC - mechanical collector
O - EPA-5 test data obtained in industry tests
|-| - average

[b]More detailed information on the emission test data and the data sources may be found in Appendix C.

[c]During testing.

[d]Analysis of the coal/RDF mixture.

[e]Analysis of the coal showed the following composition: Moisture - 24.9%; Ash (dry) - 9.9%; Sulfur (dry) - 0.9%.

Figure 4.1-26. Particulate Emissions from RDF/Coal Cofired Boilers Controlled by Mechanical Collectors[a,b]

The emission levels achieved range from 590 ng/J (1.4 $lb/10^6$ Btu) down to 170 ng/J (0.40 $lb/10^6$ Btu). These data show no clear trend on the effect of adding RDF to coal on PM emissions controlled by mechanical collectors.

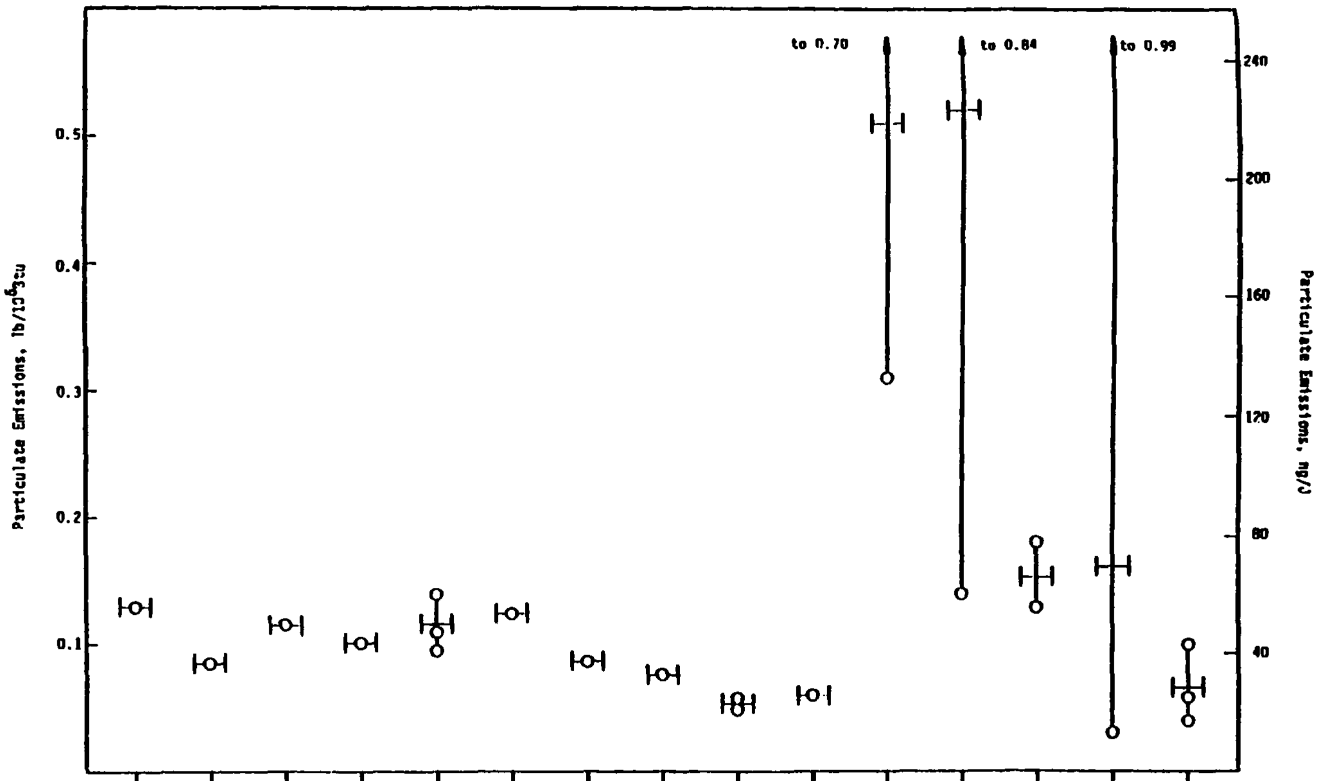
Figure 4.1-27 shows the available emission data for RDF-fired and RDF/coal cofired boilers controlled by ESPs. The data shown were obtained from 3 different facilities. Three different types of RDF were burned at these facilities: fluff RDF; densified RDF; and wet pulped RDF. Additional information on these RDF types is presented in Chapter 3.

Data from two of these facilities (HC and HG) were obtained as part of experimental programs evaluating the use of RDF as a supplementary fuel in existing coal-fired boilers. The percentages of RDF fired ranged from 0 to 27 percent (heat input basis) at the facility firing fluff RDF (HC) and 0 to 51 percent at the facility firing densified RDF (HG). The third facility (HF) fired 100 percent wet pulped RDF and was the only system tested that was specifically designed for RDF firing.

For facilities cofiring RDF and coal the data show emission levels during cofiring similar to these from coal fired alone. Therefore, ESPs should be capable of controlling emissions of coal/RDF mixtures to the same levels as coal fired alone.

Facility HC fired fluff RDF and low sulfur coal in a large pulverized coal boiler. The percentage of RDF fired during testing ranged from 0 to 27 percent and the boiler load ranged from 64 to 96 percent of capacity. The SCA during testing was fairly low ranging from 16 - 28 $m^2/(m^3/s)$ (82 - 140 $ft^2/1000$ acfm) and the emission levels ranged from 23 - 56 ng/J (.05 - 0.13 $lb/10^6$Btu). The emission levels for RDF/coal cofiring were similar to those for 100 percent coal firing.

Facility HG fired densified RDF with coal in a spreader stoker. The percentage of RDF fired during testing ranged from 0 to 51 percent and the boiler load varied from 84 to 95 percent of rated capacity. Again, the emission levels for RDF/coal cofiring were similar to those of 100 percent coal firing. The SCA during testing was fairly low, with the average of each test series ranging from about 35 - 38 $m^2(m^3/s)$ (180 - 190 $ft^2/1000$ acfm). The average emissions for high sulfur coal fired alone were 220 ng/J



Test #	HC16	HC18	HC20	HC10	HC12	HC14	HC2	HC4	HC6	HC8	HG1[c]	HG2[c]	HG3[c]	HG4[c]	HF1
Boiler Type	PC	PC	PC	PC	PC	PC	PC	PC	PC	PC	SS	SS	SS	SS	SS
Design Capacity - (10^3 lb/hr steam)	925	925	925	925	925	925	925	925	925	925	150	150	150	150	200
Nonfossil Fuel Type	-	RDF	RDF	-	RDF	RDF	-	RDF	RDF	RDF	-	d-RDF	-	d-RDF	RDF
% Heat Input[h]	-	9	18	-	9	18	-	9	18	27	-	25	-	36[d]	100
% Ash (dry)	-	17.5	17.1	-	15.3	17.9	-	18.5	12.5	13.3	-	30.7	-	13.8	16.2[i]
% Moisture	-	22.1	20.0	-	30.4	23.6	-	23.2	44.0	37.8	-	21.7	-	32.8	51.0[i]
Other Fuel	LSC[e]	LSC[e]	LSC[e]	LSC[e]	LSC[e]	LSC[e]	LSC[e]	LSC[e]	LSC[e]	LSC[e]	HSC[f]	HSC[f]	LSC[g]	LSC[g]	-
Load Factor - %[h]	96	96	96	80	80	80	64	64	64	64	95	84	94	91	80
% O_2 in flue gas[h]	5.7	5.8	5.3	6.6	5.8	6.0	6.7	6.0	6.5	5.6	9.1	10.9	10.6	10.2	7.8
Control Device	ESP	ESP	ESP	ESP	ESP	ESP	ESP	ESP	ESP	ESP	MC/ESP	MC/ESP	MC/ESP	MC/ESP	MC/ESP
Operating Parameter - SCA[h] (ft^2/1000 acfm)	92	82	97	140	113	110	142	139	134	140	184	186	176	192	326
Design Parameter - SCA (ft^2/100 acfm)	135	135	135	135	135	135	135	135	135	135	188	188	188	188	248

Figure 4.1-27. Particulate Emissions from RDF-Fired and RDF/Coal Cofired Boilers Controlled by ESPs.[a,b]

Footnotes to Figure 4.1-27:

[a]All data were obtained by EPA Method 5 and meet established criteria for acceptability. The key for the data is:

- SS - spreader stoker
- PC - pulverized coal
- LSC - low sulfur coal
- RDF - refuse derived fuel
- d-RDF - densified refuse derived fuel
- MC - mechanical collector
- ESP - electrostatic precipitator
- SCA - specific collection area
- O - EPA-5 test data obtained from industry sources
- |-| - average

[b]More detailed information on the emission test data and the data sources may be found in Appendix C.

[c]Shown here are the minimum and maximum values for the test and the average of all test runs. The number of test runs conducted for each test are as follows:

- HG1 - four runs
- HG2 - three runs
- HG3 - six runs
- HG4 - fourteen runs

[d]The actual percentage of d-RDF varied from 23 to 51 percent with the majority of the test runs firing 31 to 37 percent d-RDF.

[e]The average composition for the coal fired during testing is as follows: Moisture - 6.34%; Ash (dry) - 7.03%; Sulfur (dry) - 1.56%.

[f]Analyses of the coal showed the following range of compositions: Moisture - 5.5 to 9.9%; Ash (dry) - 15.6 to 18.2%; Sulfur (dry) - 4.2 to 6.8%.

[g]Analyses of the coal showed the following range of compositions: Moisture - 4.0 to 7.4%; Ash (dry) - 9.5 to 12.9%; Sulfur (dry) - 1.7 to 2.2%.

[h]Average value during testing.

[i]A fuel analysis was not done during testing. These data were obtained from industry sources and represent the typical fuel composition for RDF fired at this facility.

($0.51\ lb/10^6 Btu$), and for high sulfur coal cofired with 25 percent RDF were 220 ng/J ($0.52\ lb/10^6 Btu$). The average emissions with low sulfur coal fired alone were 64 ng/J ($0.15\ lb/10^6 Btu$), and low sulfur coal cofired with RDF were 69 ng/J ($0.16\ lb/10^6 Btu$). The low sulfur coal had a considerably lower ash content (11%) than the high sulfur coal (17%) on a dry basis. These tests showed considerable variation in emission levels between test runs. The reasons for this variability are unknown, but are not believed to be due to the addition of RDF to the coal because they are highly variable for both RDF/coal and coal fired alone.

ESPs have shown the capability of continuous control of emissions from coal-fired boilers to levels below 43 ng/J ($0.10\ lb/10^6$ Btu). Because of the high and variable emissions shown by this particular ESP it is not considered to be an example of a well designed and operated system.

Facility HF fired 100 percent wet pulped RDF in a spreader stoker. The average SCA at this facility during testing was 64 $m^2/(m^3/s)$ (330 $ft^2/1000$ acfm). This SCA is more than 1.5 times the SCAs of the two RDF/coal cofired boilers tested. The average emissions for this facility were 30 ng/J ($0.07\ lb/10^6 Btu$). These emissions are similar to levels shown for MSW-fired boilers controlled by ESPs with similar SCAs.

4.1.6.5 Visible Emissions Data. The available visible emissions data for control devices on nonfossil fuel fired boilers are summarized in Table 4.1-2. Data are available for boilers fired with wood, wood/fossil fuel, bagasse, MSW, and RDF.

Nine opacity tests were performed on boilers firing wood fuels or cofiring wood/fossil fuels. On four of these boilers, particulate emissions were controlled by a mechanical collector followed by a wet scrubber. These wet scrubbers had average flue gas pressure drops of 1.5-2.5 kPa (6-10 in. w.c.). The average opacity measured for these scrubbers ranged from 15.7 to 22.9 percent. The highest six minute average opacity ranged from 20.2 to 26.9 percent. The other five opacity tests were performed on wood-fired or wood/fossil fuel cofired boilers with mechanical collectors followed by an ESP or fabric filter for particulate control. In four of these tests, the particulate emission rate was measured simultaneously with opacity. The

TABLE 4.1-2. VISIBLE EMISSIONS DATA FROM NONFOSSIL FUEL FIRED BOILERS[a,b]

Plant	Boiler Type	Design Capacity (10^3 lb/hr steam)	Fuel Type	Nonfossil Fuel % Heat Input	Operating Rate % of Capacity	Control Device(s)	Particulate Emission Rate, ng/J(lb/10^6Btu)[f]	Average Opacity of All Six Minute Periods, Percent	Maximum Opacity Any Six Minute Period, Percent
BP	SS	2 x 20	HF,SD	100	95	MC/LWS	-	17.6	20.2
AF	SS	120	B,W	100	78	MC/LWS	-	22.9	26.9
AE	SS	120	B,S,W	100	88	MC/LWS	-	17.1	22.1
BO	SS	180	HF	100	100	MC/LWS	-	15.7	26.7
BA	SS	110	B	100	78	MC/ESP	-	0.5	6.5
BH[c]	PC/SS	140/200	LSC/B	0/100	48/88	MC/ESP	40.0(0.093)	0.1	1.7
							19.8(0.046)	0.1	4.6
BI[d]	SS	240/325	B,LSC	25	87	MC/ESP	18.5(0.043)	0.6	10.2
							19.4(0.045)	0.8	18.8
BJ	SS	600	B,S,HSO	61	78	MC/ESP	11.2(0.026)	0	0
BC	DO	3 x 50	SHF	100	91	MC/FF	8.7(0.020)	3.8	13.5
DD	SS	288	Bagasse	100	68	2xMC[e]	123(0.285)	18.6	21.9
FB	SS	135	MSW	100	79	MC/ESP	-	3.0	14.4
FC	SS	2 x 175	MSW	100	82	ESP	-	3.9	5.8
HF[g]	SS	200	RDF	100	75	MC/ESP	21.5(0.05)	4.0	12.5

Footnotes for Table 4.1-2.

[a]All of the data were obtained by EPA Method 9 and meet established criteria for acceptability. The key for the data is:

HF - hog fuel (wood/bark mixture)
SHF - salt-laden hog fuel
B - bark
W - wood
S - shavings or sawdust
LSC - low sulfur coal
HSO - high sulfur residual oil
MSW - municipal solid waste
RDF - refuse derived fuel
SS - spreader stoker
PC - pulverized coal
DO - Dutch oven
MC - mechanical collector
LWS - low pressure drop wet scrubber (less than 15 inches of water)
ESP - electrostatic precipitator
FF - fabric filter

[b]More detailed information on the emission test data and the data sources may be found in Appendix C.

[c]Flue gas from two boilers is combined in a single duct; flow is split and sent to two separate ESPs, each with its own stack. The PC boiler fires 100 percent coal and the SS boiler fires 100 percent bark. Each boiler has an individual mechanical collector. Data are shown for each ESP stack.

[d]Flue gas from two boilers is combined in a single duct; flow is split and sent to a two chamber ESP with two stacks. Each boiler has a individual mechanical collector and fires a mixture of wood and coal. Data are shown for each ESP stack.

[e]Two mechanical collectors in series.

[f]Particulate emission rates (where shown) were measured simultaneously with opacity.

[g]This test consisted of three test runs with opacity data being taken simultaneously with the particulate emission tests. However, the opacity data on test run one was incomplete and therefore was not used in NSPS development. The particulate emission data show the average of the two runs for which opacity data were available.

particulate emission rates measured ranged from 8.7 to 40.0 ng/J (0.020 to 0.093 lb/10^6Btu). The average opacities measured at these facilities were 0 to 0.8 percent for the boilers firing nonsalt-laden wood 3.8 percent for the one boiler firing salt-laden wood. The highest six minute opacity 18.8 percent.

One opacity test was performed on a boiler firing bagasse which had two mechanical collectors in series for particulate control. This boiler had an average opacity of 18.6 percent and a maximum six minute average of 21.9 percent. Particulate emission testing conducted simultaneously with the opacity test showed an average emission rate of 123 ng/J (0.285 lb/10^6Btu).

Two opacity tests were performed on MSW-fired boilers with ESPs for particulate control. These tests showed average opacities of 3 and 3.9 percent. The maximum opacities for any six minute period were 5.8 and 14.8 percent, respectively.

One opacity test was available on a RDF-fired boiler with a mechanical collector and ESP in series for particulate control. The average opacity was 3.9 percent and the maximum opacity for any six minute period was 12.5 percent. Two emission test runs conducted simultaneously with the opacity test showed an average particulate emission rate of 21.5 ng/J (0.05 lb/10^6Btu).

4.2 POST-COMBUSTION CONTROL TECHNIQUES FOR SULFUR DIOXIDE

As discussed in Chapter 3, boilers fired totally with nonfossil fuels emit only small quantities of SO_2. Because of the low amounts of SO_2 emitted, these boilers employ no SO_2 control techniques. Boilers cofiring nonfossil and fossil fuels, however, can have high SO_2 emissions. Because of these cases, several techniques for controlling SO_2 emissions are presented and discussed in this chapter.

Control of SO_2 emissions from these boilers can be accomplished with either pre-combustion or post-combustion techniques. Pre-combustion techniques are discussed in Section 4.3. Post-combustion control of SO_2, discussed in this section, can be accomplished by using one or more of the following techniques:

- sodium scrubbing
- dual alkali scrubbing
- lime and limestone scrubbing (with and without adipic acid addition)
- dry scrubbing.

Each of these FGD systems is currently being used commercially to remove SO_2 from industrial boiler flue gases with the exception of adipic acid enhanced FGD. Each system relies on either a calcium- or sodium-based sorbent to react with SO_2 to form sulfite and sulfate salts, thereby removing SO_2 from the flue gas stream.

Sections 4.2.1 through 4.2.4 present a description of each system and a brief evaluation of its development status, applicability, and design and operating characteristics. Section 4.2.5 presents continuous monitoring test data substantiating the performance of each technique. Because of the limited application of SO_2 controls to nonfossil fuel fired boilers, the reported data will describe SO_2 controls applied to fossil fuel fired boilers.

4.2.1 Sodium Scrubbing

Sodium scrubbing processes are capable of achieving high SO_2 removal efficiencies over a wide range of inlet SO_2 concentrations. However, these processes consume a premium chemical (NaOH or Na_2CO_3) and produce an aqueous waste for disposal which contains sodium sulfite and sulfate salts.

4.2.1.1 Process Description. Sodium scrubbing processes currently being used in industrial boiler FGD applications employ a wet scrubbing solution of sodium hydroxide (NaOH) or sodium carbonate (Na_2CO_3) to absorb SO_2 from the flue gas. The operation of the scrubber is characterized by a low liquid-to-gas ratio (1.3 to 3.4 l/m^3 [10 to 25 $gal/1000\ ft^3$]), and a sodium alkali sorbent which has a high reactivity relative to lime or limestone sorbents. Further, the scrubbing liquid is a solution rather than a slurry because of the high solubility of sodium salts. The SO_2 absorption reactions which take place in the scrubber are:[65]

$$2\ NaOH + SO_2 \rightarrow Na_2SO_3 + H_2O \quad (4.2.1\text{-}1)$$

$$Na_2CO_3 + SO_2 \rightarrow Na_2SO_3 + CO_2 \quad (4.2.1\text{-}2)$$

$$Na_2SO_3 + SO_2 + H_2O \rightarrow 2NaHSO_3 \quad (4.2.1\text{-}3)$$

Simultaneously some sodium sulfite reacts with the oxygen in the flue gas to produce sodium sulfate:

$$Na_2SO_3 + 1/2\ O_2 \rightarrow Na_2SO_4 \quad (4.2.1\text{-}4)$$

The scrubber effluent, therefore, consists of a mixture of sodium salts.

Solids storage and handling equipment are auxiliaries associated with sodium scrubbing systems. Sodium reagent handling requirements include dry storage, usually in silos. A conveyor system is generally used to transport the reactant from the silo to a mixing tank, where the sodium alkali is dissolved to produce the scrubbing solution. The solution from the mix tank is pumped to a larger hold tank where it combines with the scrubber effluent. Most of the hold tank liquor is recycled to the scrubber with a slip stream going to waste treatment and disposal. A simplified process flow diagram is presented in Figure 4.2-1.

4.2.1.2 Development Status. Sodium scrubbing systems are commercialized technology; operating systems are in use on industrial boilers ranging in size from 10 to 125 MW (35 to 430 x 10^6 Btu/hr) thermal input. Table 4.2-1 presents a summary of operating sodium scrubbing systems applied to U.S. industrial boilers. Currently 102 sodium FGD systems are in operation on domestic industrial boilers, and 23 are in the planning or construction stage.[66]

4.2.1.3 Applicability to Nonfossil Fuel Fired Boilers. Sodium scrubbing, because it is simple both chemically and mechanically, can be applied to boilers of varying size and type. As shown in Table 4.2-1, the

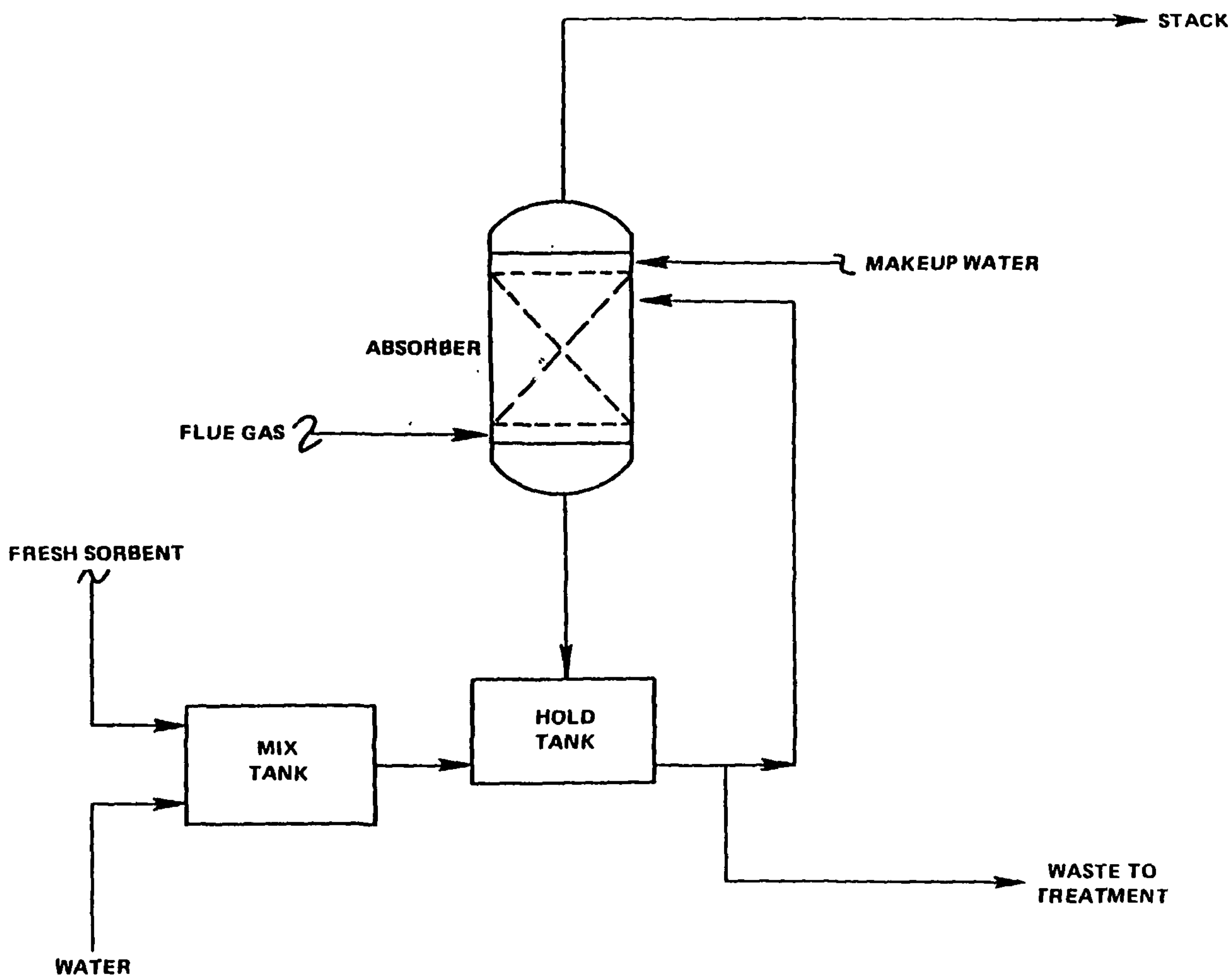


Figure 4.2-1. Simplified flow diagram of a sodium scrubbing system.

TABLE 4.2-1. SUMMARY OF OPERATING SODIUM SCRUBBING SYSTEMS[66]

Installation/location	Sorbent	Fuel Type(1)	Fuel %S	Start-up Date	No. of FGD Units	SO_2(2) Inlet (ppm)	Percent(2) Removal	Waste Disposal
Alyeska Pipeline Valdez, Alaska	NaOH	O	<0.1	6/77	1	150	96	oxidation/dilution
American Thread Martin, NC	Caustic waste	C	1-1.5	1973	2	500	70	pond
Belridge Oil McKittrick, CA	NaOH	O	1.1	6/78	2	500	90	waste water treatment
Canton Textiles Canton, GA	Caustic waste	C	0.8	6/74	1	500	70	pond/waste treatment
Chevron Bakersfield, CA	Na_2CO_3	O	1.1	7/78	3	700	90	pond/waste treatment
FMC Green River, WY	Na_2CO_3	C	1	5/76	2	800	95	pond
General Motors Dayton, OH	NaOH	C	0.7-2.0	9/74	2	1.43#/10^6BTU	86	clarify/adjust pH/ to sewer
General Motors Pontiac, MI	NaOH	C	0.8	4/76	2	—	—	combine with ash/ landfill
General Motors St. Louis, MO	NaOH	C	3.2	1972	2	2000	90	oxidize/neutralize/ discharge
General Motors Tonawanda, NY	NaOH	C	1.2	6/75	4	1#/10^6 BTU	90	combine with ash/ landfill
Georgia Pacific Crossett, AK	Caustic waste	B,C,O	1.5-2	7/75	1	500	80	to city sewers
Getty Oil Bakersfield, CA	Na_2CO_3	O	1.1	6/77-12/78	6	600	90-96	pond
Great Southern Cedar Springs, GA	Caustic waste	B,C,O	1-2	1975	2	1000	85-90	ash pond
ITT Rayonier Fernandina, FL	Caustic waste	B,O	2-2.5	1975	2	1200	80-85	to paper process
Kerr-McGee Trona, CA	Na_2CO_3	O	0.5-5	6/78	2	—	98	pond
Mead Paperboard Stevenson, AL	Na_2CO_3	O	1.5-2	1975	1	1500	95	to paper process
Mobil Oil San Ardo, CA	Na_2CO_3/NaOH	O	2-2.5	1974	28	1500	90	pond
Nekoosa Papers Ashdown, AK	Caustic waste	C	1-1.5	2/76	2	600	90	waste treatment
Northern Ohio Sugar Freemont, OH	NaOH	C	1	10/75	2	—	—	pond
St. Regis Paper Cantonment, FL	NaOH	B,O	<1	1973	1	—	80-90	clarification/ aeration
Texaco San Ardo, CA	NaOH	O	1.7	11/73	32	1000	73	pond/wells/softening and reuse
Texasgulf Granger, WY	Na_2CO_3	C	0.7	9/76	2	860	90	pond

(1) C=coal
O=oil
B=bark

(2) SO_2 Inlet (ppm) and percent SO_2 removal are as reported to PEDCo by the FGD system operator. Values reported may represent anything from single point wet chemically determined numbers to continuous monitoring results and may or may not be obtained by approved EPA methods.

process has been applied to oil-fired boilers, coal-fired boilers, and boilers cofiring bark and oil or bark, oil, and coal.

Future applications of sodium scrubbing systems may be limited by the need to dispose of the sodium sulfite/sulfate waste liquor. As shown in Table 4.2-1 the majority of sodium scrubbing systems in use today are located in the California oil fields where the wastes are disposed of in evaporation ponds or by deep well injection. Systems in use at industrial plant locations either reuse the waste liquor in various plant processes or dispose of it in ponds, landfills, or city sewers. Many pulp and paper plants may be able to re-use the waste liquor in the pulping process. If wastes from future sodium scrubbing systems cannot be disposed of by treating them in existing waste water or ash disposal facilities, or by use as a plant process make-up stream, costs associated with achieving a zero discharge waste will more than likely limit the system's application.[67]

4.2.1.4 Availability/Reliability. The three indices used in the EPA Industrial Boiler FGD Survey to reflect system performance are availability, operability, and reliability. These indices are defined as follows:

Availability - Hours the FGD system was available for operation (whether operated or not) divided by the hours in the period, expressed as a percentage.

Operability - Hours the FGD system was operated divided by boiler operating hours in the period, expressed as a percentage.

Reliability - Hours the FGD system operated divided by the hours the FGD system was called upon to operate, expressed as a percentage.

Overall reliability of sodium scrubbing systems applied to industrial boilers has generally been quite high. Data reported in the EPA Industrial Boiler FGD Survey indicate that of the 22 industrial boiler installations which have operating sodium scrubbing systems, 15 reported quantitative reliability or operability indices that ranged from 89 to 100 percent with an average of 97.8 percent. Of the 15 responses, 9 reported a 100 percent reliability/operability and all but two reported reliabilities of greater than 95 percent.[68]

Of the seven installations that did not report quantitative reliability indices, two reported that the FGD system had no problems, two reported erosion/corrosion problems, one had down-time due to reconstruction, one had mechanical problems with pump packings, and one installation did not report comments.[69]

4.2.1.5 Factors Affecting Performance. For a given set of boiler operating conditions, the SO_2 removal performance of a sodium scrubber depends on two main factors: the relative amount of scrubbing liquid circulated through the scrubber (represented by the liquid to gas ratio or L/G) and the sorbent feed rate. Although design L/G ratios are dependent on the type of gas-liquid contactor used by the process vendor, sodium scrubbing systems have relatively low L/G ratios (compared to lime or limestone systems) due to the high reactivity of the sodium alkali. Sodium scrubbing L/Gs are generally in the range of 1.3 to 3.4 l/m^3 (10 to 25 gal/1000 ft^3) whereas typical L/Gs for lime and limestone scrubbers are in the range of 5 to 15 l/m^3 (35 to 100 gal/1000 ft^3).[70]

The amount of fresh sorbent added to the system should be sufficient to replace the spent sorbent discharged with the process waste-water stream. If insufficient sorbent is added, the SO_2 removal performance of the scrubber will decrease. If more than the required amount of sorbent is added, its concentration will build up in the system and may eventually result in chemical scale. In addition, adding too much fresh sorbent will increase process operating costs. A pH controller is used to monitor the sorbent feed rate. A pH measurement below a specified set point will result in an increase in the sorbent rate whereas a high pH measurement will decrease the sorbent feed rate.

4.2.2 Double Alkali

The double or dual alkali process uses a clear sodium alkali solution for SO_2 removal and produces a calcium sulfite and sulfate sludge for disposal. Although double alkali processes produce a throwaway byproduct, a regeneration step is employed to regenerate the active alkali for SO_2 sorption.

4.2.2.1 Process Description. The double alkali processes developed in the U.S. use lime as the calcium alkali, but other processes developed in Japan and still in the development stage in the U.S. use limestone. A simplified flow diagram of a typical double alkali system is given in Figure 4.2-2. The process can be divided into three principal areas: absorption, regeneration, and solids separation. The principal chemical reactions for a sodium/lime double alkali system are illustrated by the following equations:[71]

Absorption

$$2\ NaOH + SO_2 \rightarrow Na_2SO_3 + H_2O \qquad (4.2.2\text{-}1)$$

$$Na_2CO_3 + SO_2 \rightarrow Na_2SO_3 + CO_2 \qquad (4.2.2\text{-}2)$$

$$Na_2SO_3 + 1/2\ O_2 \rightarrow Na_2SO_4 \qquad (4.2.2\text{-}3)$$

Regeneration

$$Ca(OH)_2 + 2NaHSO_3 \rightarrow Na_2SO_3 + CaSO_3\ 1/2\ H_2O + 3/2\ H_2O \qquad (4.2.2\text{-}4)$$

$$Ca(OH)_2 + Na_2SO_3 + 1/2\ H_2O \rightarrow 2NaOH + CaSO_3\ 1/2\ H_2O \qquad (4.2.2\text{-}5)$$

$$Ca(OH)_2 + Na_2SO_4 + 2H_2O \rightarrow 2NaOH + CaSO_4\ 2H_2O \qquad (4.2.2\text{-}6)$$

In the scrubber, SO_2 is removed from the flue gas by reaction with NaOH and Na_2CO_3, according to Equations 4.2.2-1 and 4.2.2-2. Because oxygen is present in the flue gas, oxidation also occurs in the system, according to Equation 4.2.2-3. Most of the scrubber effluent is recycled back to the scrubber, but a slipstream is withdrawn and reacted with slaked lime in the regeneration reactor according to reactions 4.2.2-4, 4.2.2-5, and 4.2.2-6. The presence of sulfate in the system is undesirable in that it converts

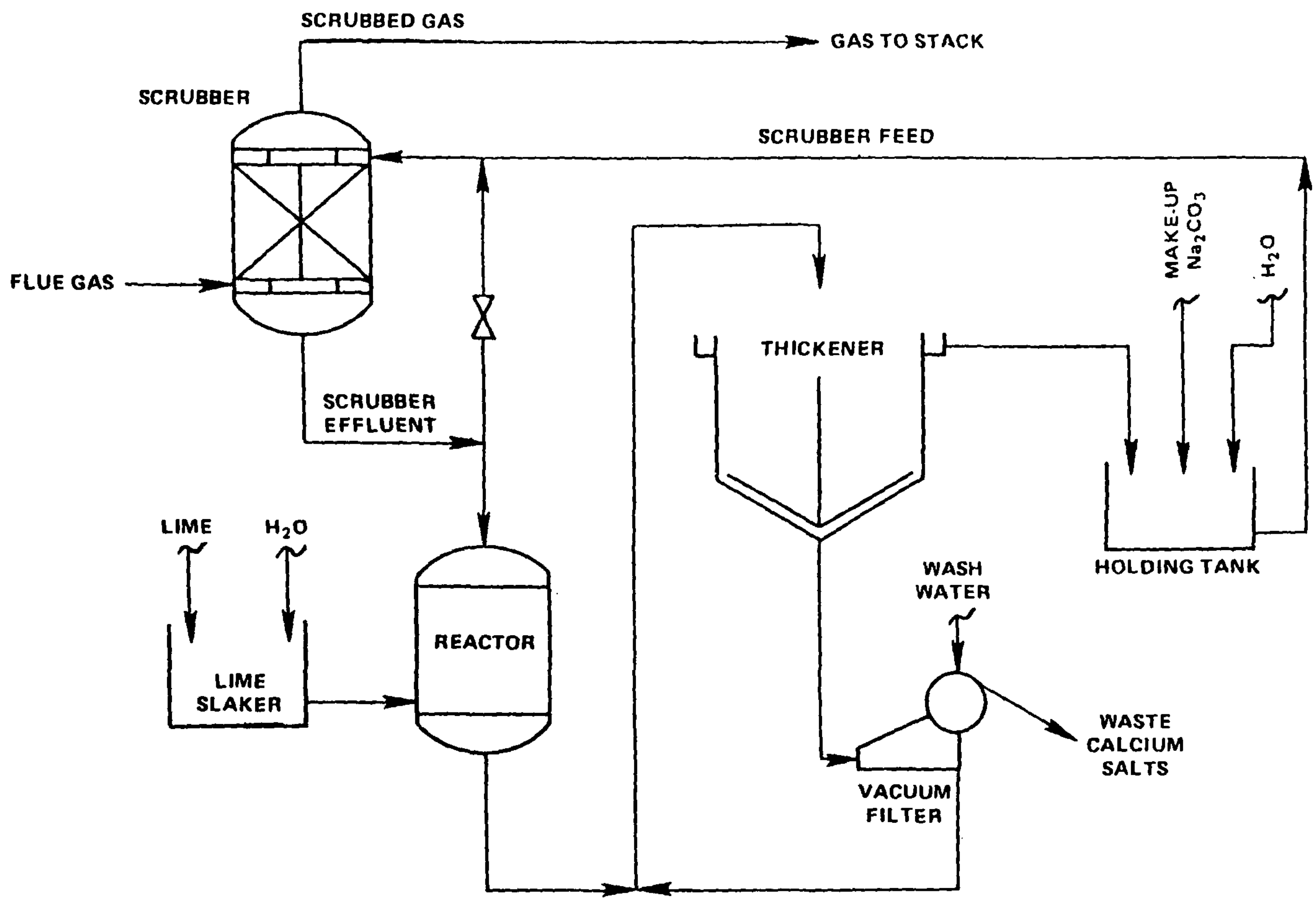


Figure 4.2-2. Simplified flow diagram for a sodium/lime double-alkali process.[72]

active sodium to an inactive form, thus lowering SO_2 removal or increasing sodium consumption for a fixed SO_2 removal.

The regeneration reactor effluent, which contains calcium sulfite and sulfate is sent to a thickener where the solids are concentrated. The thickener overflow is returned to the system, and the underflow containing the calcium solids is further concentrated in a vacuum filter (or other device) to about 50 percent solids or more. The solids are washed to reduce the soluble sodium salts in the adherent liquor prior to disposal, and the wash water is returned to the scrubber.[73]

4.2.2.2 Development Status. Several process vendors currently offer double alkali systems commercially in the United States. Double alkali systems are currently operating or planned for use at ten industrial boiler sites, with the smallest application treating 230 Nm^3/min (8100 scfm) and the largest treating 8640 Nm^3/min (305,000 scfm) of gas.[74] Table 4.2-2 presents a summary of double alkali scrubbing systems applied to U.S. industrial boilers.

4.2.2.3 Applicability to Nonfossil Fuel Fired Boilers. Although double alkali scrubbing is generally applicable to boilers cofiring nonfossil and fossil fuels, specific characteristics of the fossil and nonfossil fuels will affect system design and performance. As described in Section 4.2.2.5, the fuel characteristics having the greatest impact on design and operation are the sulfur and chloride contents. Systems applied to boilers cofiring nonfossil fuels, which are naturally low in sulfur, with other low sulfur fuels will require the use of a dilute absorbing solution to avoid regeneration problems. Some of the nonfossil fuels, such as RDF, contain relatively high amounts of chlorides (over 0.1%). Cofiring these fuels with other high chloride fuels could cause high chloride levels in the scrubbing loop resulting in stress corrosion and possibly reducing concentrations of active alkali. As described below, a prescrubber can be used to remove the chlorides before the double alkali system. Another possible design solution to the chloride problem is the specification of construction materials that will resist chloride attack.

TABLE 4.2-2. SUMMARY OF OPERATING AND PLANNED INDUSTRIAL BOILER DOUBLE ALKALI SYSTEMS.[74]

Installation/Location	Vendor or Developer	Size (SCFM)	No. of FGD Units	Fuel Type	Fuel %S	SO_2[(1)] Inlet (ppm)	SO_2[(1)] Removal (%)	Waste Disposal
ARCO Polymers Monaca, PA	FMC	305,000	3	C[(2)]	3	1800	90	Landfill
Caterpillar Tractor Co. East Peonia, ILL	FMC	210,000	4	C	3.2	2000	90	Landfill
Caterpillar Tractor Co. Juliet. ILL	ZURN	67,000	2	C	3.2	2000	90	Landfill
Caterpillar Tractor Co. Mapleton, ILL	FMC	236,000	5	C	3.2	2000	90	Landfill
Caterpillar Tractor Co. Morton, ILL	ZURN	38,000	2	C	3.2	2000	90	Landfill
Caterpillar Tractor Co. Mossville, ILL	ZURN	140,000	4	C	3.2	2000	90	Landfill
Firestone Tire and Rubber Pottstown, NY	FMC	8070	1	C	2.5-3.0	1000	90.5	Landfill
General Motors, Corp. Parma, OH	G.M.	128,400	1	C	2.5	800-1300	90	Landfill
Grisson Air Force Base Bunker Hill, IN	Neptune/ Airpol	32,000	1	C	3.0-3.5	--------	--	Landfill
Santa Fe Energy Corp. Bakersfield, CA	FMC	70,000	1	0	1.5	710	96	Landfill

(1) Inlet SO_2 and percent SO_2 removal are as reported to PEDCo by FGD system operators. Values reported may represent anything from single point wet chemical determinations to continuous monitoring results. Methods used to determine the values reported may or may not be EPA approved.

(2) C = Coal

A potential limitation of the double alkali technology, although not as severe as with the once through sodium systems, is the need to dispose of the solid waste byproduct. The waste consists of calcium sulfite and sulfate salts and generally contains from 30 to 50 weight percent water. Because of the high concentration of soluble species in the scrubbing solution, the wastes will also contain soluble salts (such as Na_2SO_3, Na_2SO_4, and NaCl) as well as the relatively insoluble calcium salts. However, the soluble salts content of the waste can be reduced to less than 1 weight percent when the waste is washed to recover the sodium.[75]

4.2.2.4 Reliability/Operability. Since there are few double alkali systems with long-term operating histories in the U.S., it is difficult to assess the overall reliability of this technology. A limited amount of data has, however, been reported in the EPA Industrial Boiler FGD Survey for seven different industrial boiler sites, and that data indicates that reported double alkali system reliability averages slightly higher than 90 percent. In addition two dual alkali systems tested by the EPA showed overall reliabilities of 89 percent and 95 percent.[76]

4.2.2.5 Factors Affecting Performance. Fuel characteristics such as the sulfur and chlorine content can have major impacts on the design and operation of a double alkali system. Major operating variables include the L/G and alkali addition rate.

Combustion of low sulfur fuels results in a higher ratio of oxygen to sulfur dioxide in the flue gas than does combustion of high sulfur fuels. The additional oxygen promotes the oxidation of sodium sulfite to sodium sulfate. Since sodium sulfate does not react with hydrated lime in the presence of concentrated sodium sulfite, some active sodium is lost in the regeneration step. This loss has the same effect as reducing the sodium alkali feedrate. Oxidation can be minimized in low sulfur fuel applications by using a dilute absorbing solution (active sodium concentration less than 0.15 Molar). At the resulting low sulfite concentrations, the sulfate will react with calcium to regenerate the scrubbing liquor. For higher sulfur applications, oxidation can be minimized by using a concentrated absorbing solution (active sodium concentration greater than 0.15 Molar) and sulfate can be coprecipitated with calcium sulfite.[77]

Chlorides absorbed from the flue gas are difficult to remove and can cause problems if they build up in the system. The only mechanism for chlorides to leave the system is in the liquor contained with the solid waste. However, chlorides are recovered and recycled to the absorber when the waste is washed to recover sodium. In addition to decreasing the concentration of active alkali in the absorber, high levels of chlorides can result in stress corrosion. A solution proposed by one vendor is to use a prescrubber to remove chlorides before the double alkali system.[78] The use of a prescrubber with a separate liquor loop, however, could cause water balance problems in the system. Since all the evaporation loss would occur in the prescrubber, the only water loss from the double alkali system would be the water occluded with the solid waste. This small water loss would not allow enough water addition for the normal cake washing (more than one displacement wash), demister washing, pump seals, and lime slaking.[79]

Another possible solution to the chloride problem is to carefully select materials of construction that will withstand chloride attack. Lined carbon steel could be used for most of the tankage, and 317 stainless steel or plastic for scrubber internals. The 317 steel has a higher molybdenum content than 316/316L steel and is more resistant to stress corrosion than 316L steel. Plastic may be preferred for small systems, but may present support problems.

The effects of variable L/G, pH, and pressure drop on double alkali process operation are shown in Figures 4.2-3 and 4.2-4 respectively. Figure 4.2-3 illustrates the increase in SO_2 removal performance due to increased L/G. Typical double alkali L/Gs range from about 1.3 to 3.4 l/m^3 (10 to 25 gal/1000 ft^3). The effects of pH are shown in Figure 4.2-4. The operating pH of the system can be adjusted by changing the sorbent feed rate and/or adjusting the pH of the regenerated liquor. In general, as shown by Figure 4.2-4, SO_2 removals decrease rapidly below pH 6. High pH levels (pH 9 or above) will result in calcium carbonate formation which can result

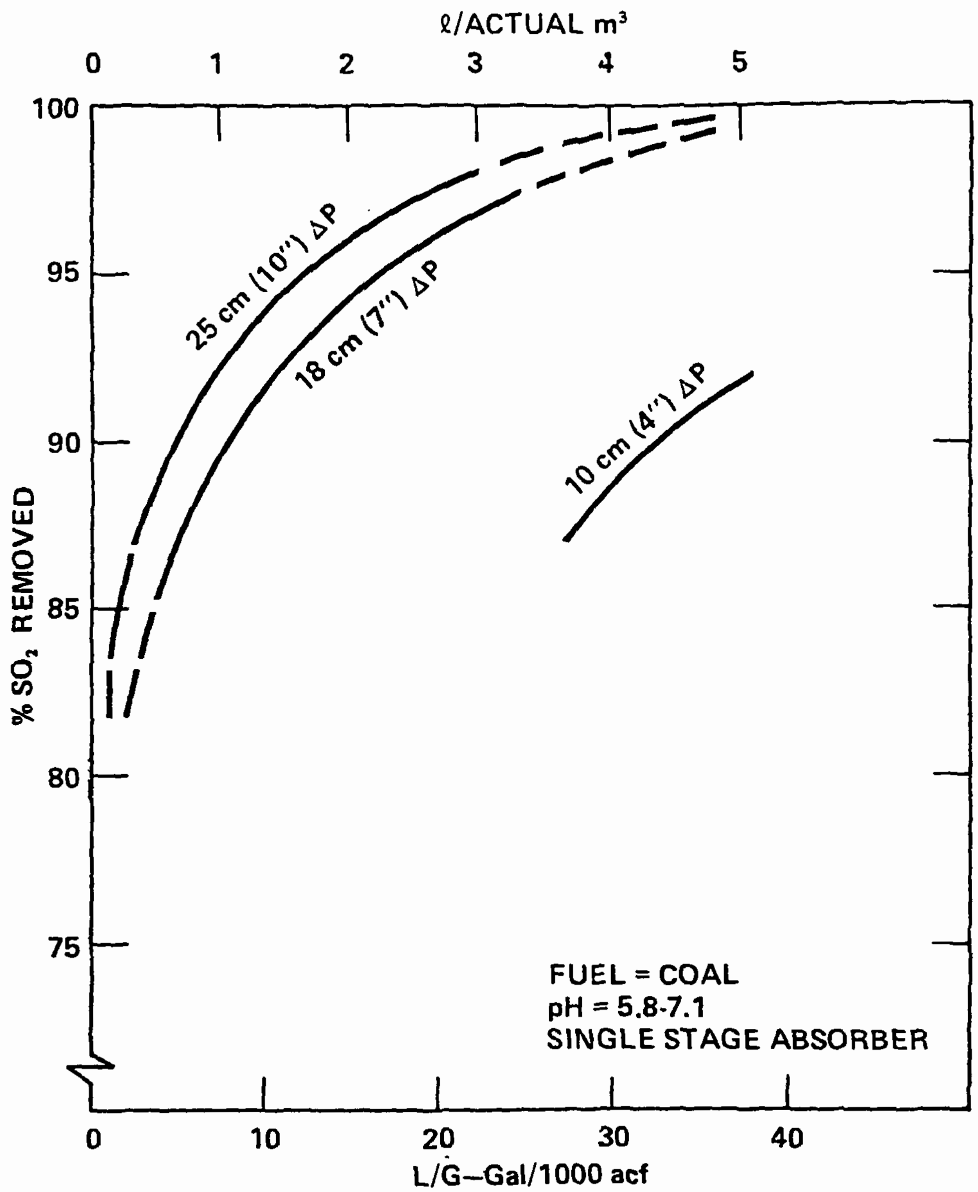


Figure 4.2-3. SO_2 removal versus L/G ratio for the Envirotech/Gadsby Pilot Plant with a single stage polysphere absorber.[80]

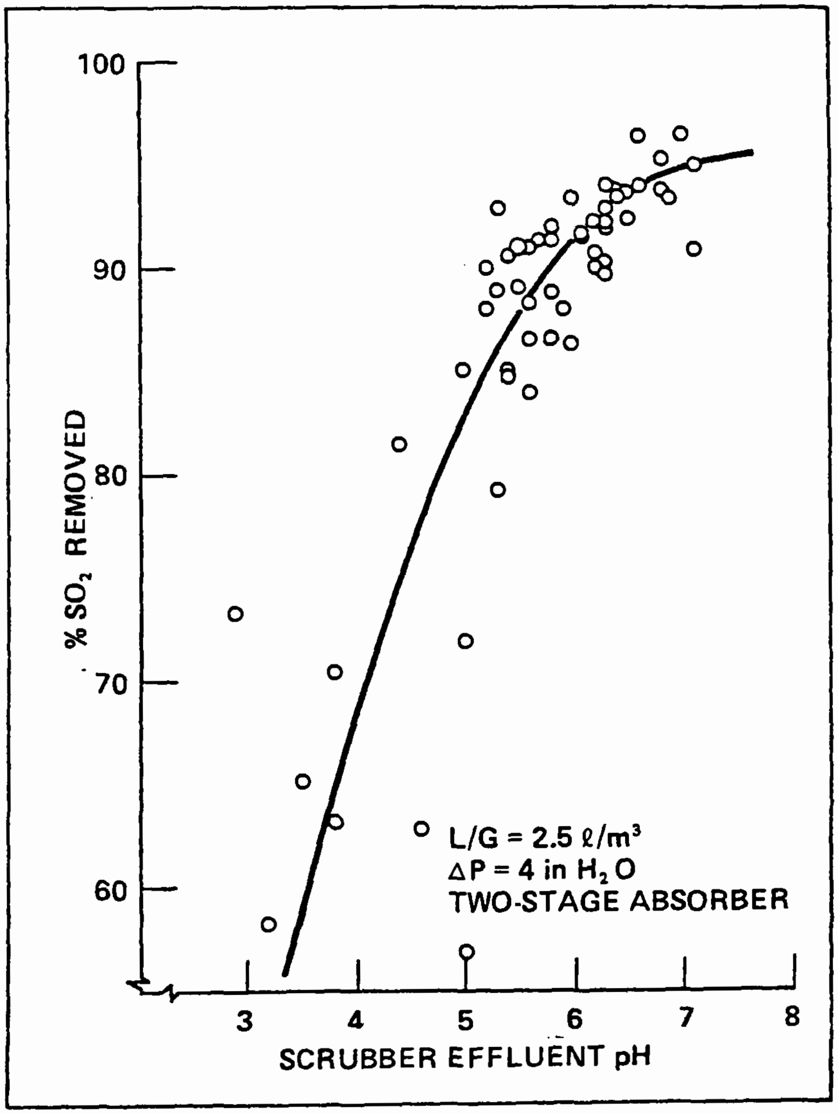


Figure 4.2-4. SO_2 removal versus scrubber effluent pH for the Envirotech/Gadsby Pilot Plant with a two-stage absorber.[81]

in scale formation. Consequently, the operating pH of double alkali systems is generally in a range of pH 6 to 8.[77]

4.2.3 Lime and Limestone

The lime and limestone FGD processes use a slurry of calcium oxide or calcium carbonate to absorb SO_2 in a wet scrubber. A byproduct calcium sulfite/sulfate sludge is produced for disposal.

4.2.3.1 Process Description. The absorption of SO_2 from flue gases by a lime or limestone slurry involves both gas-liquid, and liquid-solid mass transfer. The chemistry is complex, involving many side reactions. The overall reactions are those of SO_2 with lime (CaO) or limestone ($CaCO_3$) to form calcium sulfite ($CaSO_3$ 1/2 H_2O) with some oxidation of the sulfite to form calcium sulfate ($CaSO_4$ $2H_2O$). These reactions can be represented as follows:

Lime

$$SO_2 + CaO + 1/2\ H_2O \rightarrow CaSO_3\ 1/2\ H_2O \qquad (4.2.3\text{-}1)$$

$$SO_2 + 1/2\ O_2 + CaO + 2H_2O \rightarrow CaSO_4\ 2H_2O \qquad (4.2.3\text{-}2)$$

Limestone

$$SO_2 + CaCO_3 + 1/2\ H_2O \rightarrow CaSO_3\ 1/2\ H_2O + CO_2 \qquad (4.2.3\text{-}3)$$

$$SO_2 + 1/2\ O_2 + CaCO_3 + 2\ H_2O \rightarrow CaSO_4\ 2H_2O + CO_2 \qquad (4.2.3\text{-}4)$$

The calcium sulfite and sulfate crystals precipitate in a reaction vessel or hold tank which is designed to provide adequate residence time for solids precipitation as well as for dissolution of the alkaline additive. The hold tank effluent is recycled to the scrubber to absorb additional SO_2. A slip stream from the hold tank is sent to a solid- liquid separator to remove the precipitated solids from the system. The waste solids, which may vary from 35-70 weight percent solids, are generally disposed of by ponding or landfill. A simplified flow diagram is presented in Figure 4.2-5.

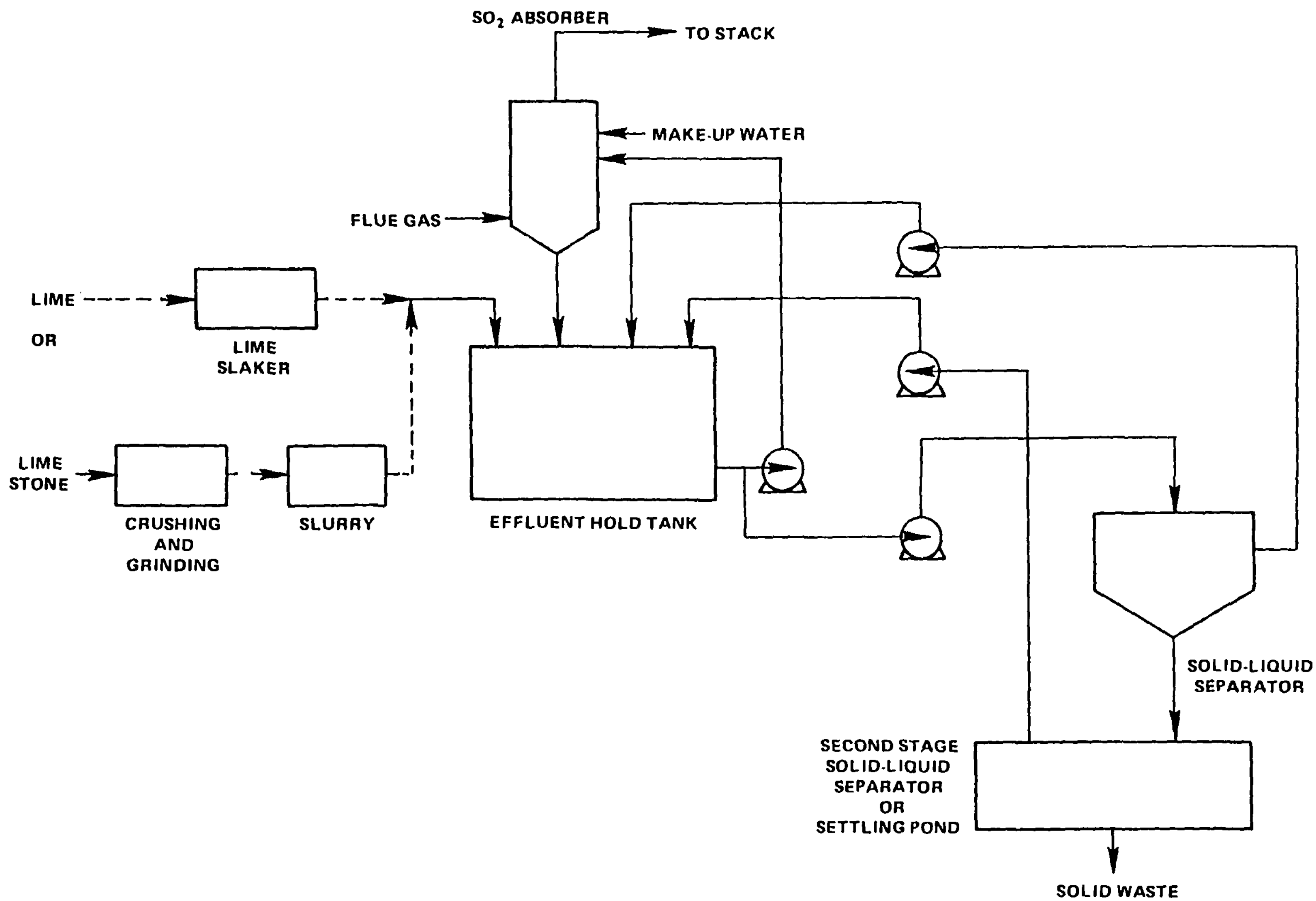


Figure 4.2-5. Process flow diagram for a typical lime or limestone wet scrubbing system.[84]

Auxiliary equipment associated with this process includes a reagent preparation system. Reagent preparation may consist of limestone grinding and slurrying or lime slaking. However, for most industrial boilers, due to their small size, preground lime and limestone may be purchased and the feed preparation system will consist of storage silos and either lime slaking or limestone slurrying equipment.

Addition of adipic acid to the FGD slurry can enhance SO_2 removal and improve the reliability and economics of lime and limestone FGD systems. Adipic acid addition provides a buffering action which limits the drop in pH that normally occurs at the gas/liquid interface during SO_2 absorption. This stablilized pH results in an increased mass transfer rate of SO_2 into the liquid phase. In addition, the capacity of the scrubbing liquor available for reaction with SO_2 is increased by the formation of calcium adipate in solution.[82] Adipic acid addition also increases lime or limestone utilization. As a result, limestone grinding requirements and solid waste generation are somewhat lower than those for a conventional limestone FGD system.[83]

4.2.3.2 Development Status. Both lime and limestone FGD technology is established and commercially available. Lime FGD technology was first used to control SO_2 emissions on commercial boiler pilot plants in England about 40 years ago.[85] As shown by Table 4.2-3, there are currently two operating systems on industrial boilers in the U.S.; one lime system treating 2380 Nm^3/min (84,000 scfm) of gas, and one limestone system treating 1560 Nm^3/min (55,000 scfm) of gas.[86]

In addition to industrial boiler use, some 34,000 MW_e of coal-fired electrical generating capacity in the United States has been committed to lime or limestone scrubbing. This figure includes 28 facilities in operation, 35 under construction, and another 16 in the planning stages (i.e., contract awarded, letter of intent signed, or requesting/evaluating bids).[85]

Emission test results from an EPA test facility at the Shawnee Power Station in Tennessee have demonstrated an average SO_2 removal of 97 percent for an industrial boiler-size, adipic acid enhanced, venturi/FGD system. A

TABLE 4.2-3. SUMMARY OF OPERATING LIME AND LIMESTONE SYSTEMS FOR U.S. INDUSTRIAL BOILERS AS OF MARCH 1978[87]

Process	Vendor	Company/Location	New or retrofit	Size scfm	Fuel	
					Type	Sulfur (%)
Lime	Koch Engineering	Armco Steel Middletown, OH	R	84,000	Coal	0.8
Lime and Limestone	Research Cottrell-Bahco	Rickenback Air Force Base Columbus, OH	R	55,000	Coal	3.6

demonstration of this technology on a full scale utility boiler is currently underway at Springfield City Utilities' Southwest Power Plant, with the results expected by the fall of 1981.

4.2.3.3 Applicability to Nonfossil Fuel Fired Boilers. Both lime and limestone processes are applicable to industrial boilers as shown in Table 4.2-3. The processes use readily available sorbents at moderate prices. As with the double alkali process, a potential limitation of the lime and limestone processes is the requirement for disposal of the waste sludge byproduct. But the problem associated with the presence of highly soluble salts in the waste is much less severe than for the double alkali or once through sodium processes.

The presence of adipic acid on the EPA's hazardous materials list should not exclude its use as an FGD additive. Bioassay tests run on sludge samples from the Shawnee facility show no significant difference in toxicity between adipic acid enhanced system sludge and sludge samples from systems without adipic acid. Additional studies on leachate toxicity have indicated that sludge generated from systems using adipic acid show toxicity to be well within EPA limits.[88]

4.2.3.4 Reliability/Operability. Reliability of lime and limestone FGD systems for industrial boiler applications is difficult to assess since there are only two installed systems in the U.S. and only one of those, the Bahco system located at Rickenbacker Air Force Base (RAFB), has been operational over a long period of time. Scrubber performance at the RAFB facility has generally been quite good except for the early stages of operation in which several startup problems resulted in significant amounts of downtime. From November 1976 through December 1978, the RAFB system illustrated that an industrial boiler FGD system can operate with high reliability as it operated 95 percent or more of the time during that period except for the months of January, February and March 1978. During those three months, system downtime was caused by a severe blizzard which resulted in the freeze-up of several lines.[89] This problem can be mitigated or avoided by insulating exposed lines and by keeping the slurry circulating through the lines whenever possible during periods of downtime in severely cold weather.

The addition of adipic acid to the lime/limestone slurry has been shown to improve overall utilization of the lime/limestone. This decreases the amount of lime/limestone solids makeup required and also the amounts of solids recirculated in the system. This should improve the overall reliability of the lime/limestone system.

In addition to good performance levels in the U.S., Japanese lime and limestone FGD systems have also demonstrated high reliabilities. Recent reports on Japanese installations have documented system reliabilities of greater than 95 percent.

4.2.3.5 Factors Affecting Performance. The removal of SO_2 from industrial boiler flue gas in a lime or limestone FGD system involves a gas-liquid-solid mass transfer process and thus is more complex than the once through sodium or double alkali FGD systems which involve only gas-liquid mass transfer in the scrubbing step. As a rule, a large portion of the alkalinity required for SO_2 removal in lime and limestone systems is derived from solids dissolution in the scrubber. Since solid-liquid reactions tend to be significantly slower than do liquid-liquid reactions, it is advantageous to minimize the amount of solids dissolution required by maximizing the amount of liquid phase alkalinity in the scrubber feed liquor. For this reason systems which operate with high magnesium and sodium concentrations but low chloride levels exhibit higher SO_2 removals than systems which are lower in soluble alkalinity.[90]

Gas maldistribution can be a major problem in lime and limestone FGD systems, particularly in large units. Unlike once through sodium and double alkali systems, lime and limestone FGD systems normally utilize "open" contactors such as spray chambers. While this practice helps to minimize potential scaling and plugging problems often associated with lime and limestone systems, it encourages gas distribution problems. Portions of the scrubber can become liquid phase alkalinity limited due to gas maldistribution even though the total alkalinity entering the scrubber is sufficient for good SO_2 removal. Scrubber design should therefore incorporate straightening vanes and/or open packing to encourage good gas distribution.[90]

Several design and operating variables should be considered in the design of a lime or limestone FGD process. The effects of the following major variables on SO_2 absorption efficiency and/or overall process operations are briefly discussed:

L/G Ratio - Higher SO_2 removal efficiences are achieved at higher L/G ratios up to the point where flooding and poor gas distribution occurs.[91] Typical L/Gs range from 5-15 l/m^3 (35-100 gal/1000 ft^3).

Slurry pH - Higher SO_2 removal efficiencies are achieved with higher pH levels. Since scaling can occur at high pH's (pH greater than 9) typical control points for a lime system are in the pH 8-9 range. Because limestone systems are buffered, they typically operate in the pH 5-6 range.[92]

Effects of Soluble Species - The concentration of dissolved ions in the scrubbing slurry directly affects the liquid phase alkalinity and hence the systems ability to remove sulfur species from flue gas. For a given set of operating conditions, high concentrations of Na^+ and Mg^{++} will improve the SO_2 removal efficiency of a system and high concentrations of Cl^- will reduce it.[93] Addition of organic acids, such as adipic acid, can also improve the performance of a limestone system by increasing the dissolved alkalinity in the scrubbing slurry and increasing the limestone utilization.[94]

Ash Removal - Although fly ash can be removed simultaneously with SO_2, the trend has been to remove it upstream for the following reasons: to decrease erosion in the scrubber and associated equipment such as pumps, piping, nozzles, and fans; to provide dry fly ash for sludge fixation; and to avoid particulate emission excursions during periods of scrubber inoperation.[95]

Oxidation - Forced oxidation systems increase the amount of calcium sulfate (gypsum) in the waste which is produced by sparging air into the system. A high sulfate sludge is more easily dewatered and has better structural properties than does the more difficult to handle thixotropic calcium sulfite sludge.[96] Application of forced oxidation to FGD systems using adipic acid additive may result in degradation of the adipic acid in the slurry. However, testing is still being conducted on these effects at Springfield City Utilities' Southwest Power Plant and the final results should be available in Fall 1981.

4.2.4 Dry Scrubbing

Dry flue gas desulfurization (FGD) processes that are generally applicable to boilers cofiring fossil and nonfossil fuels are 1) spray drying of a solution or slurry of alkaline material in a flue gas with collection of the dry FGD waste product in a baghouse or ESP, and 2) dry injection of alkaline material into a flue gas with FGD waste product collection in an ESP or baghouse. Since spray drying is the only commercially developed dry FGD process, only spray drying is discussed below.

4.2.4.1 Process Description. In a spray drying process, flue gas is contacted with a solution or slurry of alkaline material in a vessel of relatively long residence time (5 to 10 seconds).[97] Generally the particulate matter has not been removed prior to entering the absorber, and the spray drying process acts as a combined particulate/SO_2 removal system. The flue gas SO_2 reacts with the alkali solution or slurry to form liquid phase salts which are dried to about one percent free moisture. These solids, along with fly ash are entrained in the flue gas and carried out of the dryer to a particulate collection device such as an ESP or baghouse. Systems using a baghouse for particulate removal report additional SO_2 sorption occurring in the baghouse. A generalized diagram for a typical spray drying process is shown in Figure 4.2-6.

Reaction between the alkaline material and flue gas SO_2 proceeds both during and following the drying process. The mechanisms of the SO_2 removal reactions are not well understood, and it has not been determined whether SO_2 removal occurs predominantly in the liquid phase, by absorption into the finely atomized droplets being dried, or by reaction between gas phase SO_2 and the slightly moist spray dried solids. The overall chemical reactions for this process are shown below.[99]

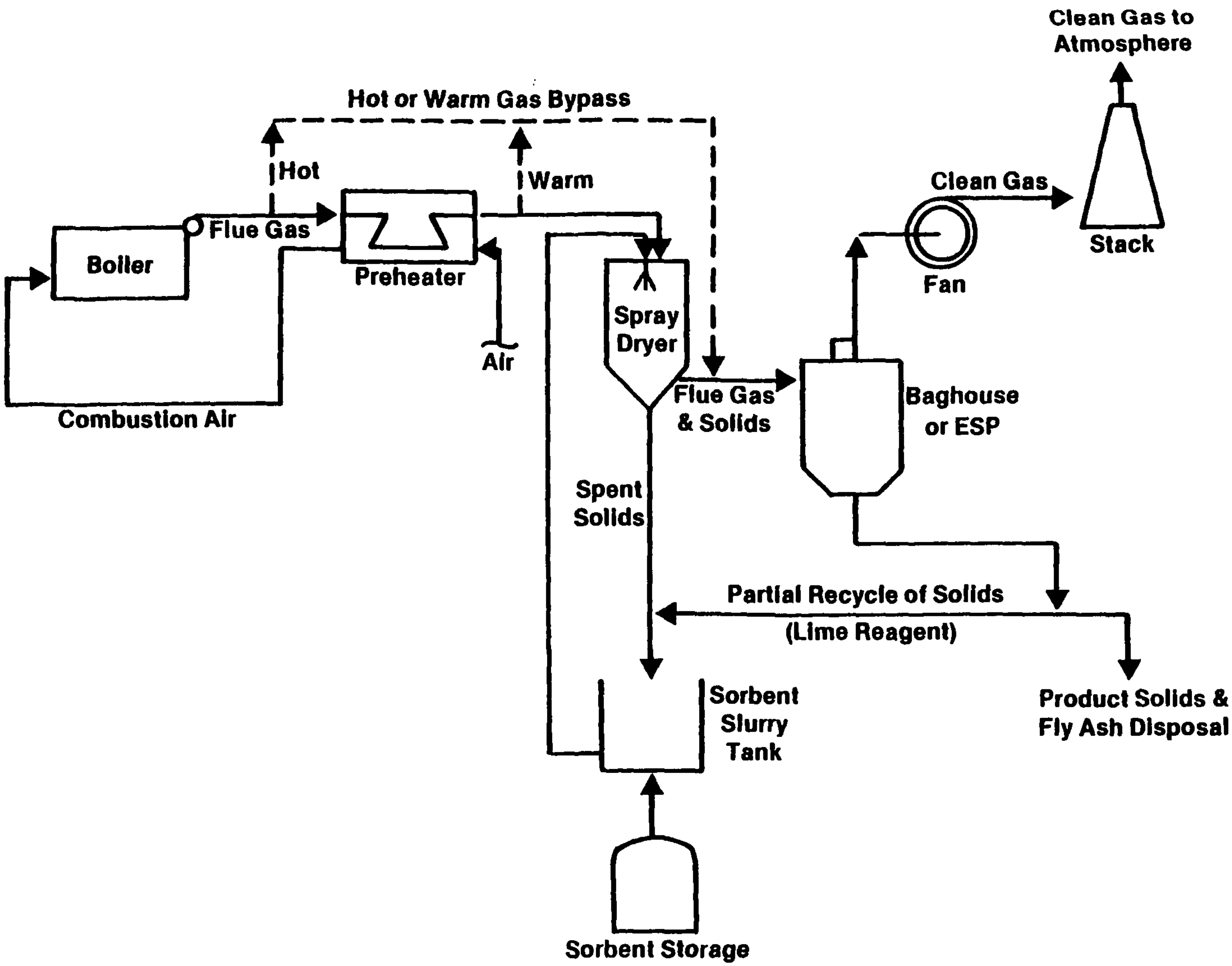


Figure 4.2-6. Typical spray dryer/particulate collection process flow diagram.[98]

$$SO_2 + Na_2CO_3 \rightarrow Na_2SO_3 + CO_2 \qquad (4.2.4\text{-}1)$$

$$SO_2 + CaO + 1/2\ H_2O \rightarrow CaSO_3\ 1/2\ H_2O \qquad (4.2.4\text{-}2)$$

In addition to these primary reactions, sulfate salts will be produced by the following reactions:

$$Na_2SO_3 + 1/2\ O_2 \rightarrow Na_2SO_4 \qquad (4.2.4\text{-}3)$$

$$SO_3 + Na_2CO_3 \rightarrow Na_2SO_4 + CO_2 \qquad (4.2.4\text{-}4)$$

$$SO_2 + CaO + 1/2\ O_2 + 2H_2O \rightarrow CaSO_4\ 2H_2O \qquad (4.2.4\text{-}5)$$

Liquid to gas (L/G) ratios for spray drying are typically 0.03 to 0.04 l/m^3 (0.2 to 0.3 gal/1,000 ft^3). This low liquid rate is not sufficient to saturate the gas. Gas exit temperatures are typically in the 65-93^oC (150 to 200^oF) range which provides a safe margin against water condensation.[100]

4.2.4.2 Development Status. Spray drying technology for removing SO_2 from boiler flue gas has been limited to pilot-scale testing of industrial boiler sized systems (280 to 560 m^3/min [10,000 to 20,000 acfm]) at several utility locations burning low sulfur western coals. This technology is being commercially offered by several vendors, and five spray drying FGD systems have been sold for industrial boiler applications. These systems are being applied to boilers burning coals with a fairly wide range of sulfur contents (0.6 to 3.5 percent S). Table 4.2-4 summarizes the commercial spray drying systems sold for application to industrial boilers. In addition eleven full scale utility systems have been sold. The utility systems are being applied to low sulfur (less than 2 percent) coal-fired units and SO_2 removal guarantees from the vendors are as high as 90 percent. However, it still remains to be shown whether spray dryer systems will be able to achieve high SO_2 removal efficiencies when applied to full scale industrial boiler installations firing a range of coal types.

TABLE 4.2-4. SUMMARY OF INDUSTRIAL BOILER SPRAY DRYING SYSTEMS[101]

Company Location	Vendor	Sorbent	Size (lb steam/hr)	Fuel Type	Fuel % Sulfur	SO_2 Removal Guarantee (%)[a]
Strathmore Paper Co. Woronoco, MA (operating)	Mikropol	Lime	85,000	Coal	2 to 2.5	75% on 3% S coal
Celanese Cumberland, MD (operating)	Wheelabrator-Frye/ Rockwell Int.	Lime	110,000	Coal	1 to 2	85% on 2% S coal
University of Minnesota Minneapolis, MN	Carborundum Environmental Systems, Inc.	Lime	2 units @ 120,000 acfm each	Coal	0.6 to 0.7	70%
Department of Energy Argonne, IL	Niro Atomizer, Inc./Joy-Western Precipitation Division	Lime	170,000	Coal	3.5	80% (1.2 lb $SO_2/10^6$ Btu)
Container Corp. Pittsburgh, PA	Ecolaire, Inc.	Lime	170,000	Coal	1	NA

NA = Not available.

[a]Vendor design guarantees under specific operating conditions.

4.2.4.3 Applicability to Nonfossil Fuel Fired Boilers. Spray drying technology is an applicable SO_2 control method for all industrial boiler types firing low to medium sulfur fuels (less than three percent sulfur). However, the technical and economic viability of this process is not clear for applications requiring high SO_2 removals (90 percent) for high sulfur fuels (such as coals containing more than three percent sulfur).

Some NFFBs, such as those firing mixtures of wood and fossil fuels, will have higher moisture contents in the flue gas than boilers firing fossil fuels alone. This could prevent the successful application of a spray drying system. However, other nonfossil fuels, such as RDF, have lower moisture contents than most wood fuels. Therefore, the increase in flue gas moisture content when firing RDF/fossil mixtures will not be as great as the increase for wood/fossil mixtures.

The potential for condensation in downstream particulate collection equipment, especially during system upsets, is also a concern. Condensation problems may be avoided by bypassing the fabric filter during system upsets and by maintaining spray dryer outlet temperatures at an adequate margin above the adiabatic saturation point. The effects of condensation on downstream equipment, and system performance using varying quality fuels are questions that will be resolved only after additional operating experience is obtained in either utility or industrial boiler applications.

4.2.4.4 Reliability/Operability. Since dry scrubbing is a relatively recent innovation in industrial boiler FGD no data are available on the long term reliability or operability of these systems. However, since they are less complex mechanically and no more complex chemically than wet calcium or sodium based scrubbing systems they should ultimately prove to be at least as reliable and operable.

4.2.4.5 Factors Affecting Performance. The performance of a spray dryer FGD system depends on several factors, the two most important being the L/G ratio and the stoichiometric ratio of sorbent to SO_2. Unlike a wet scrubbing system the amount of water that can be added (measured by the L/G) is limited by heat balance (or dew point) considerations for a given inlet flue gas temperature and approach to saturation. Typical L/G ratios range from 0.03 to 0.04 l/m^3 (0.2 to 0.3 gal/1000 ft^3). The stoichiometry is varied by raising or lowering the concentration of a solution or slurry containing this fixed amount of water. As sorbent stoichiometry is increased to raise the level of SO_2 removal, there are two potentially limiting factors:[102]

- Sorbent utilization may decrease, raising sorbent and disposal costs per unit of SO_2 removed.
- An upper limit on the solubility of the sorbent in the solution, or on the weight percent of sorbent solids in a slurry may be reached.

Methods of circumventing these limitations include recycling sorbent, either from solids dropped out in the spray dryer or from the particulate collection device[103] and operating the spray dryer at a lower outlet temperature; that is, at a closer approach to saturation.[104]

Based upon pilot unit test results high SO_2 removals (up to 90 percent) can be achieved for low-sulfur coal applications, using either lime or sodium based sorbents. Stoichiometric ratios of 2.3 - 3.0 were required for lime operations whereas stoichiometric ratios of only 1.0 - 1.2 were required to achieve the same SO_2 removal for sodium operations. It has also been reported that 90 percent SO_2 removal may be achieved with a stoichiometric lime requirement of 1.3 - 1.7 by recycling some of the unreacted sorbent.[105] A sodium based system should be able to achieve higher SO_2 removals than lime based systems on high sulfur coals due to the greater reactivity of sodium hydroxide or sodium carbonate compared to lime.

Spray dryer design can also be affected by the choice of the particulate collection device. Bag collectors have an inherent advantage in that unreacted alkalinity in the collected waste on the bag surface can react with the remaining SO_2 in the flue gas. Some process developers have reported SO_2 removal on bag surfaces on the order of 10 percent.[106] A disadvantage of using a bag collector is that since the fabric is somewhat sensitive to wetting, a safe margin above saturation temperature (on the order of 25 to 35°F) must be maintained for bag protection. Some vendors claim that an ESP is less sensitive to condensation and hence can be operated closer to saturation (less than a 25°F approach) with associated increase in spray dryer performance. However, they feel that SO_2 removal within the collector is not likely to be as high as in a baghouse.[107]

4.2.5 Performance of Sulfur Dioxide Control Techniques

This section presents continuous SO_2 emission monitoring data for five wet FGD systems and a lime spray drying system. These emission data are representative of the SO_2 removal capability of well designed, operated and maintained industrial boiler wet FGD systems. All sampling and analyses were conducted in accordance with the procedures specified in 40 CFR 60 Appendix B.

As with the particulate matter emission data, tests not considered to be representative of well operated FGD systems are not presented in this chapter, but are included in Appendix C along with documentation of the reasons why they were not considered to be representative. Three such tests of wet FGD systems are discussed in Appendix C.

4.2.5.1 Emission Reduction Data for Wet FGD Systems. This section presents the results of five continuous SO_2 emission monitoring tests of industrial boiler wet FGD systems. All of the tests were conducted by EPA. Data were collected for two dilute double alkali systems, one sodium throwaway system, a lime system, and a limestone system with adipic acid addition. Table 4.2-5 summarizes the five test programs. Figures 4.2-7 to 4.2-11 show the 24-hour average SO_2 removal, boiler load, and scrubbing slurry pH. Only days with 18 hours or more of test data are presented; missing days (days where 18 hours of data were not obtained) are indicated by a break in data shown in Figures 4.2-7 to 4.2-11.

Table 4.2-5 shows that each system averaged more than 90 percent SO_2 removal over the test period. In addition, average outlet SO_2 concentrations for each test period were 192 ng/J (0.45 lb/10^6 Btu) or less.

Thirty days of continuous emissions data were gathered at the sodium throwaway scrubbing system at Location I. Figure 4.2-7 shows consistent high SO_2 removal, averaging 96.2 percent for the test period. Table 4.2-5 shows that daily average inlet SO_2 concentrations ranged from 1961 to 2480 ng/J (4.6 to 6.3 lb/10^6 Btu). The scrubbing solution pH was

TABLE 4.2-5. SUMMARY OF CONTINUOUS SO_2 EMISSION DATA AT FIVE INDUSTRIAL BOILER WET FGD SYSTEMS

			24-hr Average Results						
			Inlet SO_2 (ng/J)[c]		Outlet SO_2 (ng/J)[c]		% SO_2 Removal		
Location[a]	System Type	No. of Days of Data[b]	Range	Average[d]	Range	Average[d]	Range	Average[d]	Comments
I	Sodium Throwaway	30	1961-2480	2348	54-267	87	88-98	96	Tray & quench liquid scrubber; coal sulfur = 3.6%
III/No. 1	Double Alkali	17	1235-2000	1646	81-213	138	88-95	92	Two Tray scrubber; Design pH = 5.5 to 7.5; Design L/G = 2.7 ℓ/m³;
III/No. 3	Double Alkali	24	1180-2285	1606	37-446	128	74-97	92	Same design as Location III/#1.
IV	Lime	29	1927-2432	2250	94-294	192	88-96	91	Two "inverted venturi" stages; Coal Sulfur = 3.5%.
IV	Limestone with Adipic Acid Addition	30	1333-2765	2125	56-262	122	90-97	94	Coal sulfur 2.2 to 3.5%; Adipic Acid concentrations of 1770 to 3000 ppm.

[a]More complete descriptions, data testings, and references for test reports can be found in Appendix C.

[b]Only days with 18-hrs or more of test data are reported.

[c]Divide by 430 to convert to $lb/10^6$ Btu.

[d]Arithmetic mean of 24-hr averages for test period.

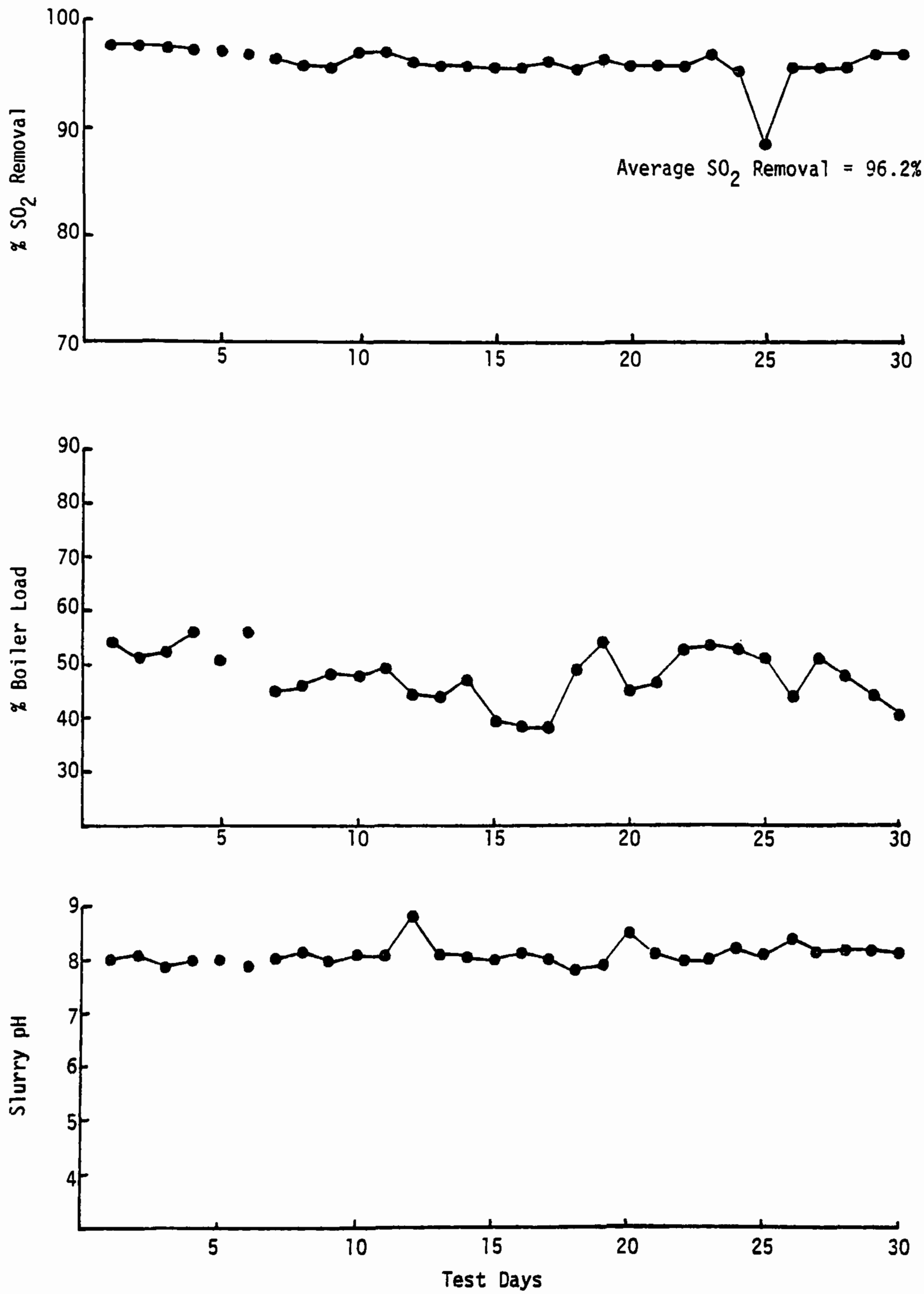


Figure 4.2-7. Daily average SO_2 removal, boiler load, slurry pH for the sodium scrubbing process at Location I.

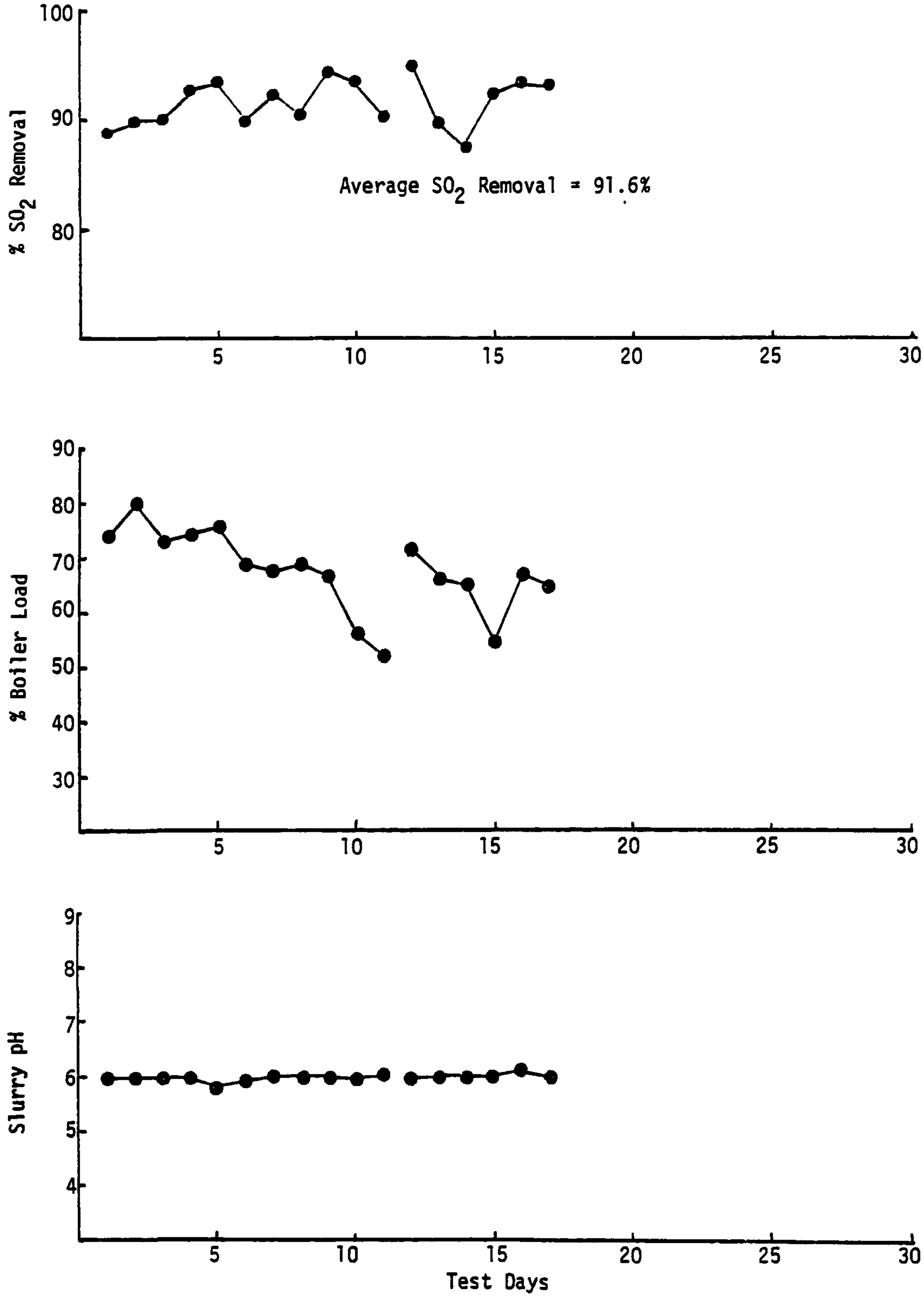


Figure 4.2-8. Daily average SO_2 removal, boiler load, and slurry pH for the dual alkali scrubbing process at Boiler No. 1, Location III.

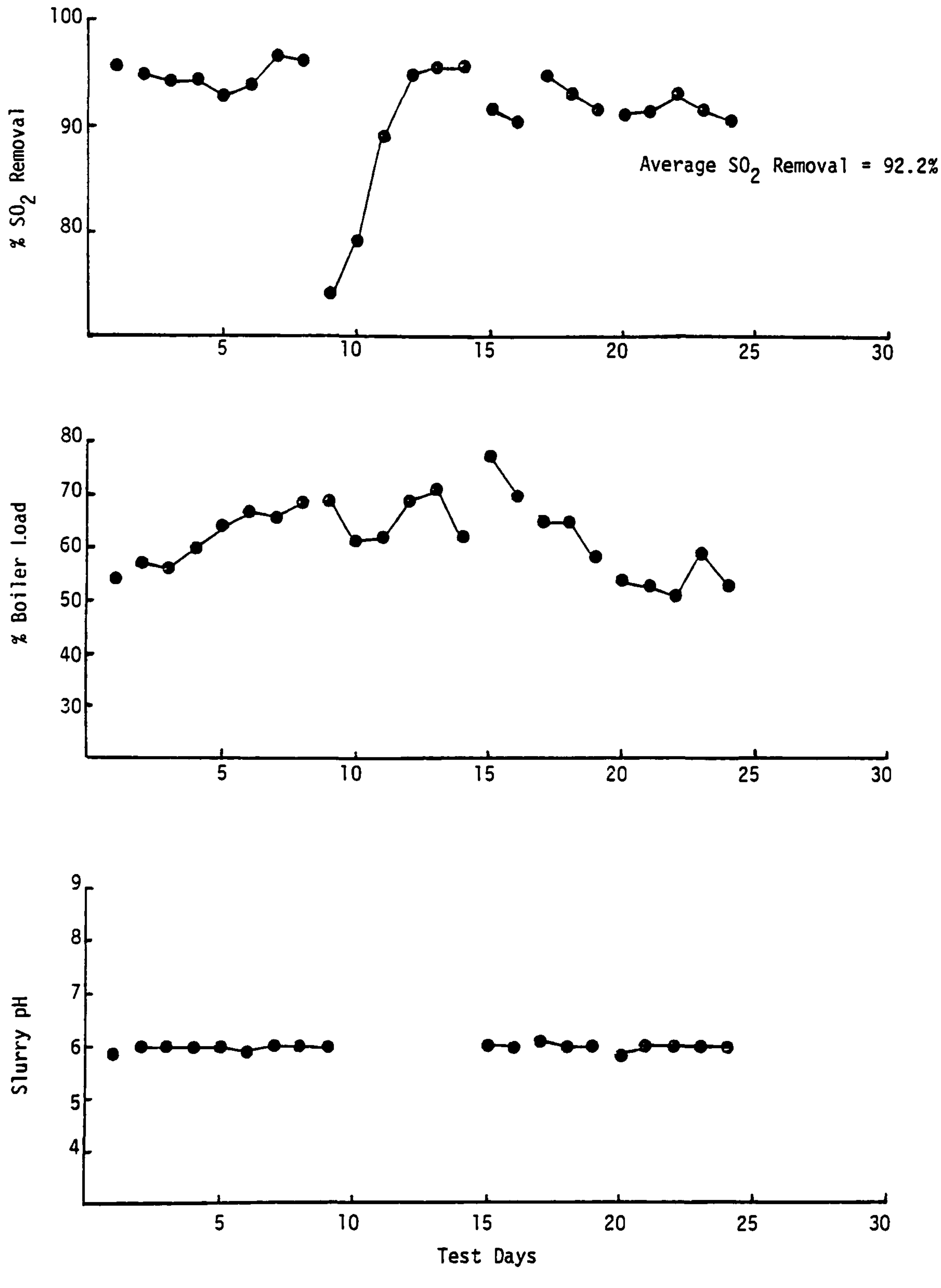


Figure 4.2-9. Daily average SO_2 removal, boiler load, and slurry pH for scrubbing process at Boiler No. 3 Location III.

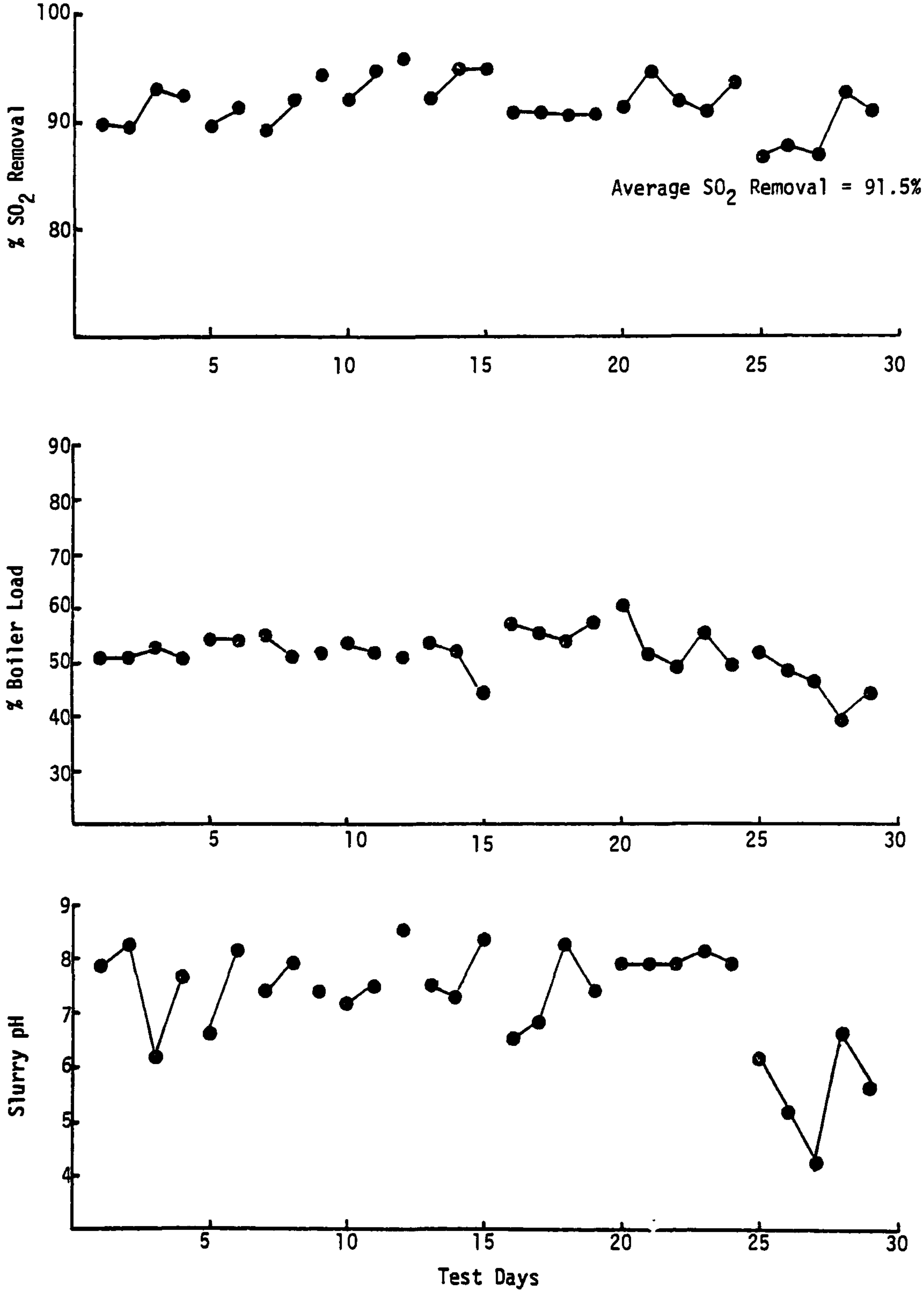


Figure 4.2-10. Daily average SO_2 removal, boiler load, and slurry pH for lime slurry scrubbing process at Location IV.

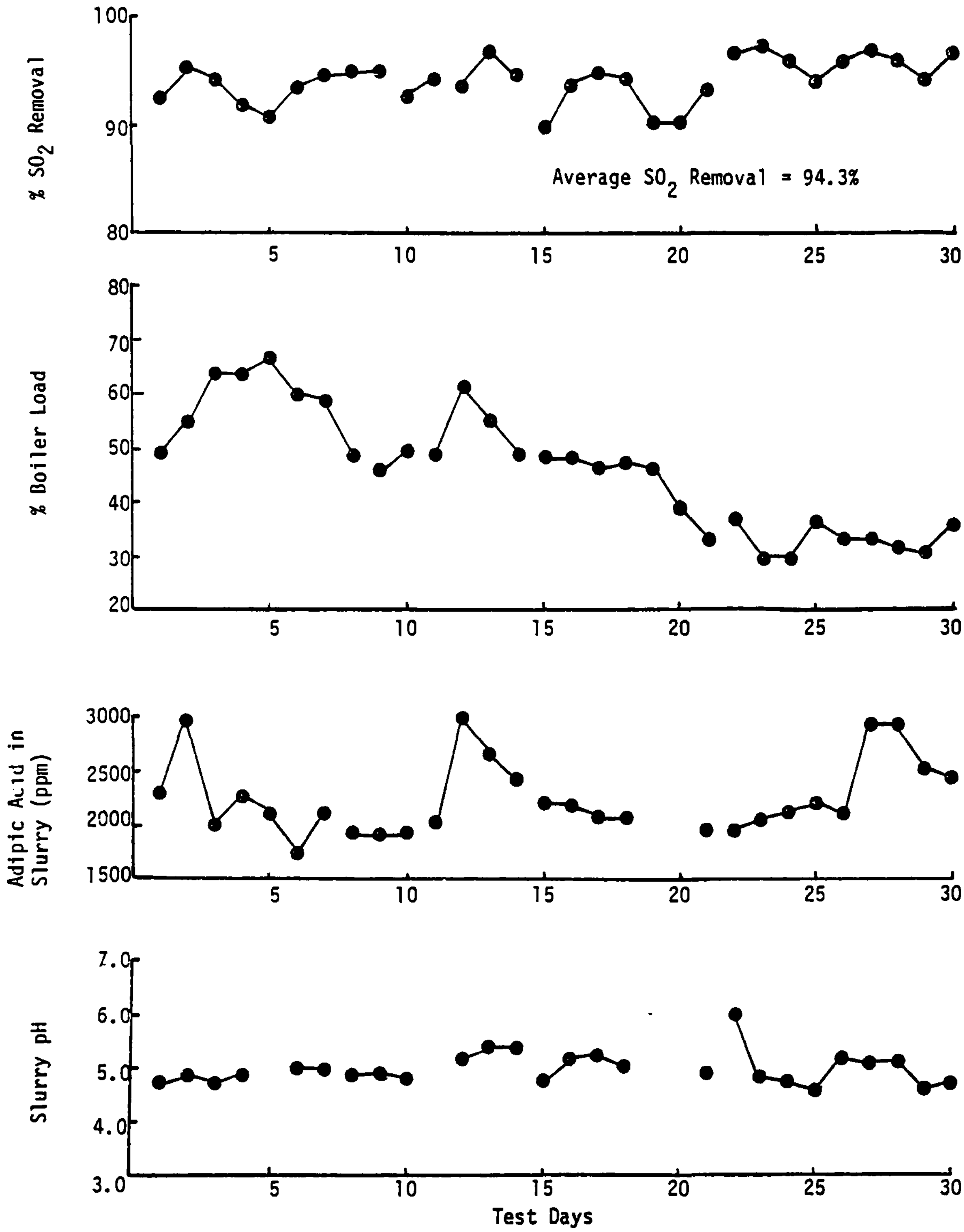


Figure 4.2-11. Daily average SO_2 removal, boiler load, adipic acid concentration, and slurry pH for limestone system at Location IV.

consistently maintained at about pH 8. As discussed in Section 4.2.1.5, proper pH control is important for maintaining the sorbent feed rate required for the desired SO_2 removal.

Figures 4.2-8 and 4.2-9 show daily average results for two similar double alkali systems at Location III. The two systems averaged 91 and 92.2 percent SO_2 removal over the respective 17- and 24-day test periods. Daily average inlet SO_2 concentrations ranged between 1235 and 2000 ng/J (2.9 and 4.7 lb/10^6 Btu) at Boiler No.1 and between 1180 and 2285 ng/J (2.8 and 5.3 lb/10^6 Btu) at Boiler No.3. The scrubbing slurry pH for both systems was maintained close to pH 6 during the test periods. The desired operating pH of most double alkali systems is pH 6 to 8 (Section 4.2.2). The design pH for the systems at Location III is pH 5.5 to 7.5 and the design L/G ratio is 2.7 l/m^3 (20 gal/10^3 ft^3).

The lowest SO_2 removals observed at Location III, Boiler No.3 (Test days 9 and 10 in Figure 4.2-9) were during FGD system start-up after the scrubber had been taken off-line due to low boiler load requirements at the plant.

Figure 4.2-10 shows the daily average results of tests of a lime scrubbing system at Location IV. Average SO_2 removal for the period was 91.5 percent and daily average inlet SO_2 concentrations ranged between 1927 and 2432 ng/J (4.5 and 5.7 lb/10^6 Btu). The lowest SO_2 removals were observed during the last few days of testing when the scrubbing slurry pH dropped below pH 6. As discussed in Section 4.2.3, typical control points for lime systems are more often in the pH 8 to 9 range. Figure 4.2-10 shows generally higher SO_2 removals for the periods during which slurry pH was maintained near pH 8.

Figure 4.2-11 presents the results of 30-days of testing at Location IV during which limestone reagent was used (instead of lime) and adipic acid was added to the scrubbing solution. These data show an average SO_2 removal of 94.3 percent for the test period. High SO_2 removals were obtained over a wide range of boiler loads. Adipic acid concentrations in the slurry ranged from 1770 to 3000 ppm and slurry pH was maintained near pH 5. Inlet SO_2 concentrations ranged from 1333 to 2765 ng/J (3.10 to 6.43 lb/10^6 Btu).

The data in Figure 4.2-11 indicate that adipic acid addition contributes to high SO_2 removals and, with proper pH and adipic acid addition control, low variability in system performance. Previous testing of the FGD system at Location IV with limestone slurry had shown SO_2 removals between 50 and 70 percent. It should be noted that adipic acid addition may not have been solely responsible for the improved SO_2 removal efficiency since the limestone only tests appeared to have been conducted at conditions outside the design range of the system (see Appendix C).

4.2.5.2 Emission Reduction Data for Lime Spray Drying System. Figure 4.2-12 illustrates the daily average results for SO_2 emission monitoring of the lime spray drying system at Location VI. SO_2 removal efficiency ranged from 46 to 80 percent and averaged 68.4 percent over the test period. SO_2 concentrations ranged from 1118 to 1905 ng/J (2.6 to 4.4 lb/10^6 Btu). Figure 4.2-12 shows SO_2 removal efficiencies averaging 75 percent on the days when average daily SO_2 concentrations were 1720 ng/J (4.0 lb/10^6 Btu) or greater. The somewhat variable performance of the spray dryer can be attributed in part to various system upsets that occurred throughout the testing period. These upsets include slurry pump problems, spray dryer plugging and boiler load fluctuations. Over the last six days of the testing program, a period in which no upsets occurred, the average daily SO_2 removal remained near 80 percent.[110]

The average sulfur content of the coal fired during the test was near 2 percent, which is the coal sulfur content the system was designed for. No data were available for spray drying systems applied to high sulfur coal-fired boilers.

4.3 PRE-COMBUSTION CONTROL TECHNIQUES FOR SULFUR DIOXIDE

As an alternative to post-combustion controls, SO_2 emissions from boilers cofiring nonfossil and fossil fuels can be controlled by pre-combustion techniques. Pre-combustion control techniques include:

- using naturally-occurring clean fossil fuels
- using physically or chemically-cleaned fossil fuels.

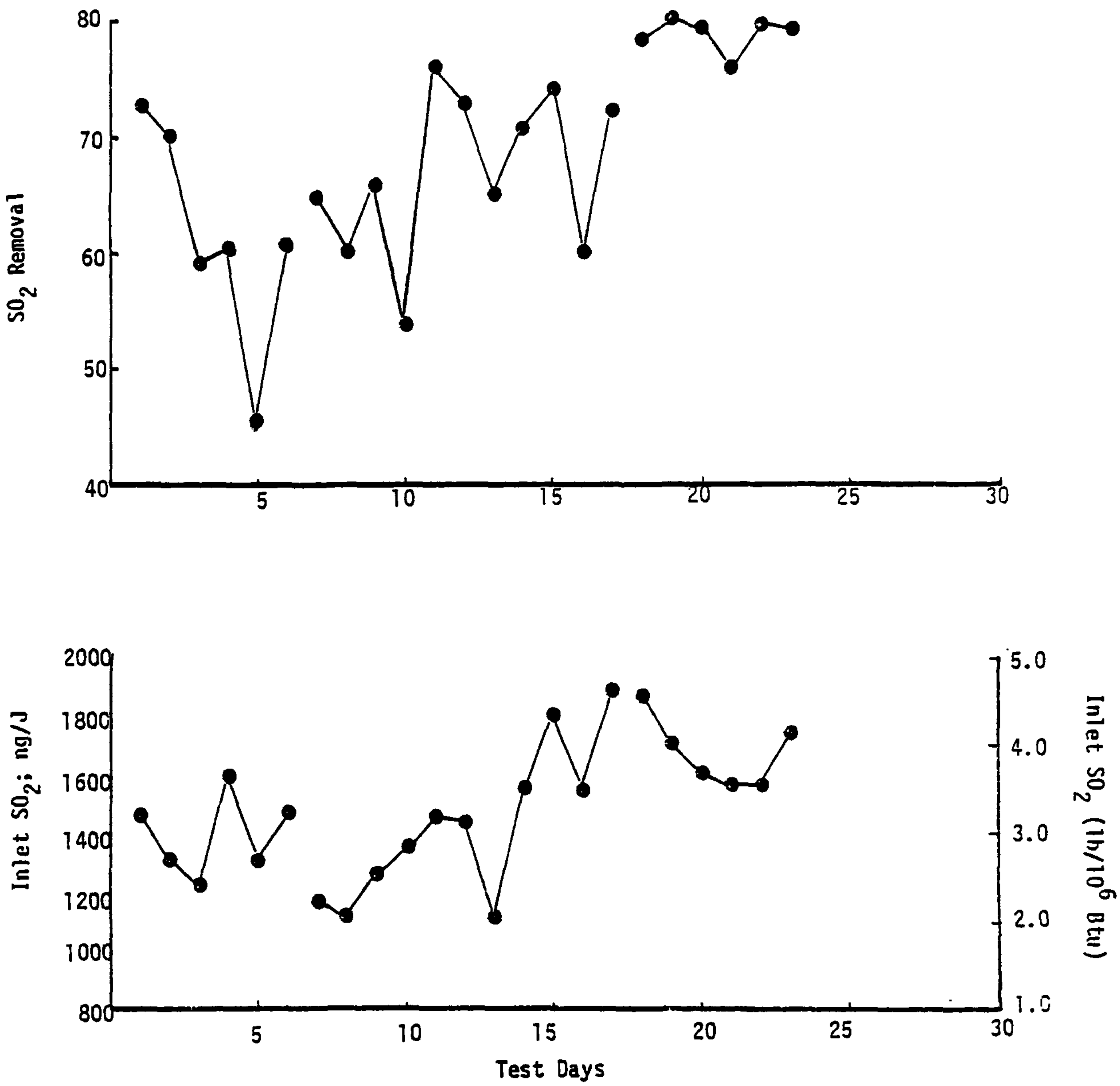


Figure 4.2-12. Daily average SO_2 removal, inlet SO_2 for lime spray system at Location VI.

Both of these techniques control SO_2 emissions by limiting the SO_2 potentially produced during fuel combustion.

Section 4.3.1 describes the use of naturally occurring clean fuels. Sections 4.3.2 and 4.3.3 discuss fuel cleaning processes. Naturally occurring clean fuels discussed in Section 4.3.1 are raw low sulfur coal and raw low sulfur oil which are low enough in sulfur content to meet SO_2 emission limits with no additional controls. The fuel cleaning processes discussed in Section 4.3.2 and 4.3.3 are physical coal cleaning (PCC) and hydrodesulfurization (HDS) of oil. These processes are primarily designed to control SO_2 emissions by reducing the sulfur content of the fuel. However, they may also aid in the control of particulate emissions by simultaneously reducing the ash content of the fuel. Oil cleaning may result in reduced NO_x emissions due to reduction of fuel nitrogen content by hydrotreating. No performance data are presented for the pre-combustion SO_2 emission control techniques because their performance is obvious and well demonstrated.

4.3.1 Naturally Occurring Clean Fuels

The naturally occurring clean fuels of interest are low sulfur coal and low sulfur crude oil. Low sulfur coal is defined as run-of-mine (ROM) coal which can comply with a given emission standard. Where no emission standard has been delineated, coals with sulfur contents of less than 1 percent by weight are considered low sulfur coals.[114]

The sulfur content of United States coals is quite variable. While 46 percent of the U.S. total reserve base can be identified as low sulfur coal because its sulfur content is less than 1 percent, 21 percent ranges between 1 percent and 3 percent in sulfur, and an additional 21 percent contains more than 3 percent sulfur. The sulfur content of 12 percent of the coal reserve base is unknown, largely because many coal beds have not been mined.

Nearly 85 percent of the reserve base of less than 1 percent sulfur coal is located in states west of the Mississippi River. The bulk of the western coals are, however, of a lower rank than the eastern coals. On a heat content basis, it is estimated that at least 20 percent of the nation's reserve of low sulfur coal is in the East.[114]

Low sulfur western coals can be burned in underfeed and traveling grate stokers as long as they are designed with sufficient control of undergrate air to handle any caking that may occur. Caking causes an uneven ash layer to form on the grate which reduces combustion efficiency unless undergrate air can be distributed properly. It has been reported that current designs of some spreader stokers cannot handle caking because they lack the ability to control undergrate air distribution.[115] Since design changes to incorporate the necessary air distribution system have not been demonstrated, the use of those low sulfur coals which cake or have a low ash fusion temperature is not applicable to these stokers. Other low sulfur coals such as eastern bituminous, which do not cake or have a low ash fusion temperature, can be burned in underfeed and traveling grate stokers. The demonstrated reserve base of low sulfur eastern bituminous coal as of January 1, 1974, was greater than 24 billion metric tons.[116]

Some spreader stokers of current design also cannot handle coals with ash fusion temperatures below 1480 K (2200°F), which are typical for many low sulfur western coals (e.g., the Wyoming subbituminous, Utah bituminous and the lignites).[117]

Pulverized coal boilers can be designed for almost any type of coal. The initial choice of fuel will determine the type of pulverizer used, the tube spacing in the boiler and superheater (low fusion temperature coals require greater spacing), and the type of materials used in the furnace wall.[118]

In 1976 domestic refinery capacity for producing fuel oil from low sulfur crude was 231,000 m^3/day (1,452,000 bbl/day), while consumption was 229,000 m^3/day (1,422,000 bbl/day). However, actual U.S. production of low sulfur fuel oil (LSFO) was 108,000 m^3/day (667,000 bbl/day), with the difference made up by imports. In contrast to low sulfur coal, LSFO derived from naturally occurring clean crude is readily applicable to all boiler types and sizes that burn a similar grade of fuel.[119]

There are no factors affecting the ability of naturally occurring low sulfur coal or oil to reduce SO_2 emissions, except the actual sulfur content of the fuel. However, the higher resistivity of the fly ash from the combustion of low sulfur coal will affect the design of an ESP relative to that for medium to high sulfur coal. The effect of resistivity on ESP performance is discussed in Subsection 4.1.4.

4.3.2 Physical Coal Cleaning

Physical coal cleaning is the generic name for all processes which remove inorganic impurities from coal, without altering the chemical nature of the coal. Basically, a coal cleaning plant is a continuum of technologies rather than one distinct technology.[120] Each coal cleaning plant is a uniquely-tailored combination of different unit operations determined by the specific coal characteristics and by the commercially dictated processing objectives.

Overall process design philosophy in coal cleaning plants is to use step-wise separations and beneficiations, with a goal of eventually treating small, precise fractions of the feed with the more sophisticated and specific unit operations. In this way, the least costly technologies are applied to large throughputs and the more costly to much smaller throughputs. A characteristic of this design philosophy is that multiple product streams evolve, each with its own set of size and purity properties. In conventional cleaning plants the separate product streams are blended prior to shipment, to produce a composite coal meeting the consumer's specifications. Within the context of supplying industrial boilers with small quantities of relatively low-sulfur fuel, every opportunity exists for premium low-sulfur coals to be segregated from the final blending operation and targeted for specialty markets.[121]

4.3.2.1 Process Description. In a modern PCC plant, coal is typically subjected to: size reduction and screening, separation of coal from its impurities, and dewatering and drying. Commercial PCC methods are currently limited to separation of the impurities based on differences in the specific gravity of coal constituents (gravity separation) and on the differences in surface properties of the coal and its mineral matter (froth flotation).[122] A generalized physical coal cleaning schematic is shown in Figure 4.3-1.

Five general levels of coal cleaning are used to categorize the degree of treatment to which a coal has been subjected. These levels are:

Level 1 -- Crushing and sizing

Level 2 -- Coarse size coal beneficiation

Level 3 -- Coarse and medium size coal beneficiation

Level 4 -- Coarse, medium, and fine size coal beneficiation

Level 5 -- "Deep cleaning" coal beneficiation

Level 1 processes are generally used to size raw coal to user specifications, and to remove overburden. No washing is done and the entire process is dry.

Levels 2 and 3, in addition to crushing and screening raw coal also perform a minimum of cleaning. Level 2 provides for removal of only coarse pyritic sulfur. Level 3 is basically an extension of Level 2 in that both the coarse and medium size fractions obtained from screening are washed whereas in Level 2 only the coarse fractions are washed.[123]

Level 4 systems provide high efficiency cleaning of both coarse and medium coal fractions with lower efficiency cleaning of the fines. The primary difference between Level 4 and the lower cleaning levels is the use of heavy media processes for cleaning specific size fractions above 28 mesh. For particles smaller than 28 mesh, cleaning by froth flotation is most commonly used. Level 4 systems accomplish free pyrite rejection and improvement of heat content.[124]

Level 5 coal preparation systems are unique in that two products are produced, a high quality, low sulfur, low ash coal called "deep cleaned" coal and a middlings product with higher sulfur and ash content. Level 5 provides the most advanced state-of-the-art in physical coal cleaning with large reductions in pyrite and ash content and improvement of heat content at high yields. In addition, this system is flexible relative to the types of coal that can be processed. Variations in raw coal and product specifications can be handled by varying the heavy medium densities and careful control of coal sizes treated in various circuits.

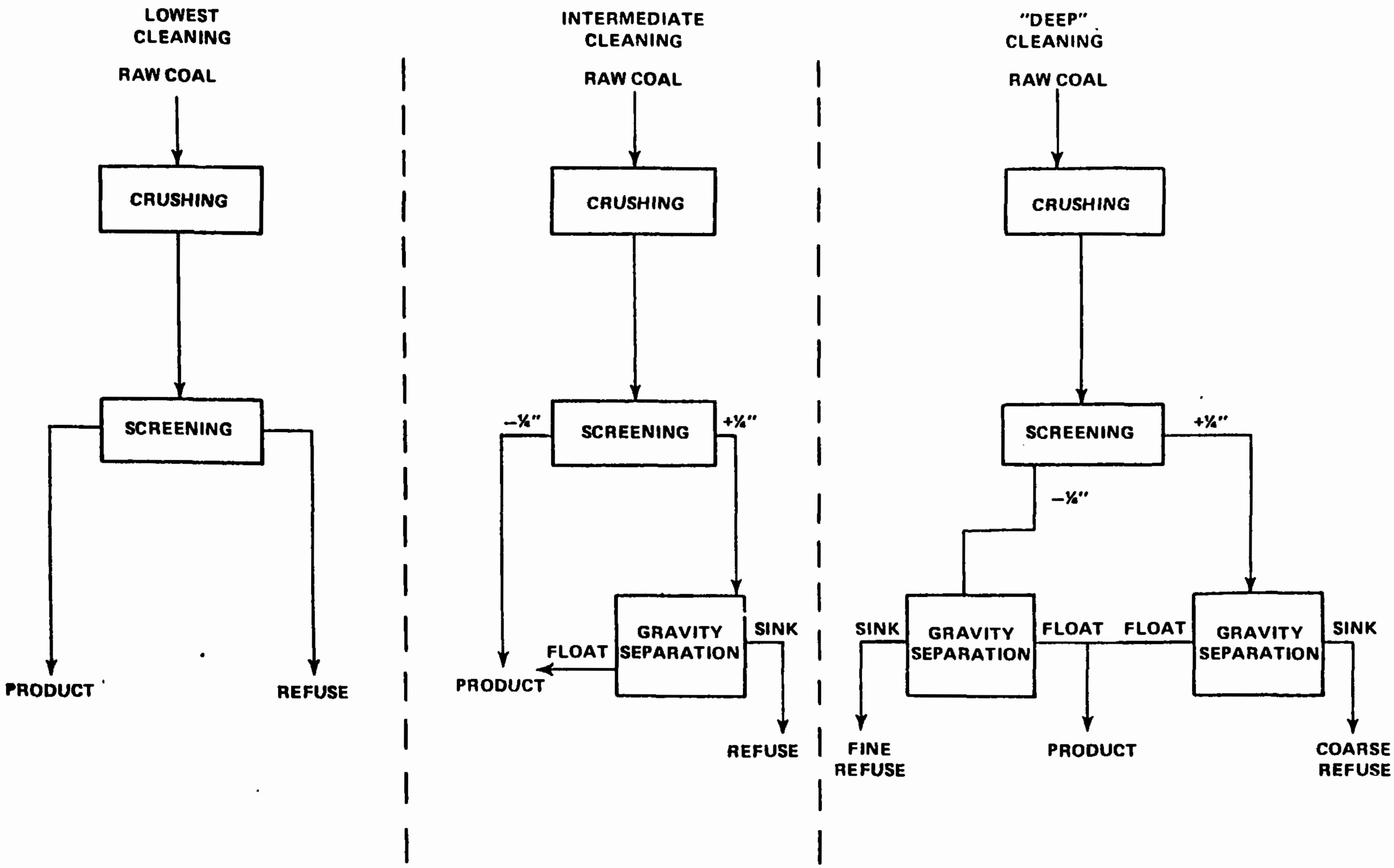


Figure 4.3-1. Physical coal cleaning unit operations employed to achieve various levels of cleaning.

Level 5 coal cleaning plants use the techniques and principles utilized in the first four levels, but combine them in unique ways to maximize mass and energy recovery. Major operations involved are crushing, screening or sizing, heavy media separation, secondary separation, dewatering and removal of fines from process water. The high efficiency of Level 5 is due to the repeated use of these operations to produce the desired products.[125]

4.3.2.2 Development status. There are currently over 460 physical coal cleaning plants in the U.S. In 1976 about 340 million tons of raw coal was processed by these plants. This represents 58 percent of the total 1976 U.S. coal production of 590 million tons. The majority of these plants were designed for ash removal rather than sulfur removal although many do take out 20-30 percent of the sulfur in the raw coal. The status of coal cleaning plants operated in 1976 is summarized in Table 4.3-1.[126] Some plants use only one major cleaning process, while the majority use a series of cleaning processes. The capacity of individual plants varies widely from less than 200 metric tons per day to more than 25,000 metric tons per day.[127]

Levels 1 through 4 are currently in use in operating commercial plants which produce steam coal. There are examples of Level 5 systems at metallurgical coal plants where both a low sulfur, low ash metallurgical grade product and a middling (higher sulfur and ash content) combustion grade by-product are produced. All unit operations proposed for a Level 5 plant are presently used in commercial plants. However, the unit operations have not yet been combined to form a commercial Level 5 plant for producing steam coal.[128]

4.3.2.3 Applicability to Nonfossil Fuel Fired Boilers. Firing of physically cleaned coal in industrial stoker-fired boilers is not expected to have a significant effect on boiler maintenance requirements. In industrial pulverized coal-fired boilers, firing of physically cleaned coal may reduce boiler maintenance costs.[129]

Physical cleaning of coal should improve the overall performance of a stoker-fired boiler provided the resultant coal size is acceptable for stoker firing (1-1/2" x 1/4" with minimal fines). Physical cleaning

TABLE 4.3-1. PHYSICAL COAL CLEANING PLANTS CATEGORIZED BY STATES FOR 1976.[126]

State	Estimated Total Coal Production, 1000 tons	Number of Coal-Cleaning Plants	Number of Plants for Which Capacity Data Reported	Total Daily Capacity of Reporting Plants, Tons	Estimated Annual Capacity of Reporting Plants,(a) 1000 tons	Number of Plants Using Various Cleaning Methods					
						Heavy Media	Jigs	Flotation Units	Air Tables	Washing Tables	Cyclones
Alabama	21,425	22	10	40,600	10,150	0	10	6	1	12	6
Arkansas	670	1	0	-	-	1	-	-	-	1	1
Colorado	8,160	2	0	-	-	2	-	1	-	-	-
Illinois	59,251	33	20	136,775	34,195	17	20	4	1	1	8
Indiana	24,922	7	6	42,000	10,500	2	5	1	-	1	3
Kansas	568	2	2	3,800	950	-	2	-	-	-	-
Kentucky	146,900	70	48	245,700	61,425	43	27	16	4	20	24
Maryland	2,792	1	0	-	-	-	-	-	-	-	1
Missouri	5,035	2	1	3,500	875	-	2	-	-	-	-
New Mexico	9,242	1	1	6,000	1,500	1	-	1	-	-	1
Ohio	44,582	18	13	102,750	25,690	6	11	-	1	2	5
Oklahoma	2,770	2	1	550	140	1	1	-	-	-	1
Pennsylvania (Anthracite)	5,090	24	14	13,000	3,250	21	4	4	-	3	2
Pennsylvania (Bituminous)	81,950	66	50	205,010	71,255	30	19	16	20	15	19
Tennessee	9,295	5	4	8,520	2,130	1	1	1	2	-	1
Utah	6,600	6	4	23,100	5,775	2	4	2	2	-	2
Virginia	36,500	42	29	143,550	35,890	26	15	9	8	15	11
Washington	3,700	2	1	20,000	5,000	1	1	-	-	-	-
West Virginia	110,000	152	113	577,375	144,345	104	55	59	12	55	59
Wyoming	23,595	1	1	600	150	-	-	-	1	-	-
Total	603,055	459	318	1,652,830	413,210	266	177	121	52	125	144

(a) The estimated annual-capacity values for the reporting plants were calculated from the daily-capacity values by assuming an average plant operation of 250 days per year (5 days per week for 50 weeks per year).

partially removes pyrites, ash, and other impurities, thus reducing both SO_2 and particulate emissions. As compared to raw coal, physically cleaned coal is easier to handle and feed, burns more uniformly with less chance for clinkering, and reduces ash disposal problems.[130] As an example, both a raw and the corresponding physically cleaned coal were fired in a steam plant spreader stoker boiler. When firing the raw coal, the boiler could operate only at about one half capacity. The high ash content of this coal resulted in nonuniform combustion caused by feeding problems, excessive ash buildup and clinker formation on the fuel bed. In contrast, the physically cleaned coal was fired at full capacity with no operational problems.[130]

4.3.2.4 Factors Affecting Performance. Sulfur reduction by physical cleaning varies depending upon the distribution of sulfur forms in the coal. There are three general forms of sulfur found in coal; organic, pyritic, and sulfate sulfur. Sulfate sulfur is present in the smallest amount (0.1 percent by weight or less). The sulfate sulfur is usually water soluble, orginating from in-situ pyrite oxidation, and can be removed by washing the coal. Mineral sulfur occurs in either of the two dimorphous forms of iron disulfide (FeS_2) - pyrite or marcasite. The two minerals have the same chemical composition, but have different crystalline forms. Sulfide sulfur occurs as individual particles (0.1 micron to 25 cm. in diameter) distributed through the coal matrix. Pyrite is a dense mineral (4.5 gm/cc) compared with bituminous coal (1.3 gm/cc) and is quite water-insoluble thus the best physical means of removal is by specific gravity separation. The organic sulfur is chemically bonded to the organic carbon of the coal and cannot be removed unless the chemical bonds are broken. The amount of organic sulfur present defines the lowest limit to which a coal can be cleaned with respect to sulfur removal by physical methods. Chemical coal cleaning processes, currently in the developmental stage, are designed to attack and remove up to 40 percent of the organic sulfur. Physical cleaning typically can remove about 50 percent of the pyritic sulfur, although the actual removal depends on the washability of the coal, the unit processes employed and the density of the separating medium.[131]

A trade-off between product yield and purity exists for any one unit operation of a physical coal cleaning process. Product yield is defined as the ratio of the clean product heating value divided by the heating value of the raw coal and can vary from 0 to 1. Product purity refers to the amount of sulfur retained in the clean product - the lower the sulfur content, the higher the purity. One unit operation cannot achieve both performance goals -- either yield is maximized, or purity is maximized, or a compromise is made between yield and purity. This basic limitation on performance also applies to an entire plant if that plant only produces one clean coal product. However, the designer of a multi-product plant may achieve both performance goals. As an example, one unit operation may be selected for maximizing product purity although the quantity of this clean product is relatively small. In this case, a fine fraction (28 x 0 mesh) may be produced with a pyritic sulfur content reduced by up to 90 percent, but with a yield of less than 50 percent. If the rejected portions are washed again at a relatively high specific gravity in another (sequential) unit operation, a "middling" product with somewhat higher pyritic sulfur content may be recovered with an overall recovery (between the two products) of the majority of the original heating value.[132]

The inherent design advantages of a multi-product plant do have special significance for industrial boilers. Since the coal quantities used by industrial boilers are a small fraction of the total coal demand, it might be quite attractive for a coal cleaning plant to produce a very clean product for new industrial boilers and a middling product suitable either for consumers subject to less stringent emission standards or for large consumers (i.e., utilities) with additional site-specific SO_2 controls.[133]

4.3.3 Oil Cleaning

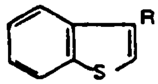
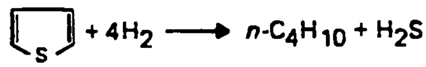
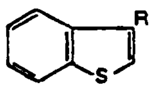
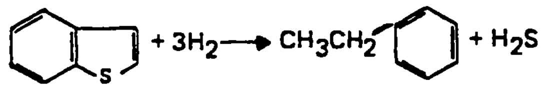
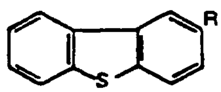
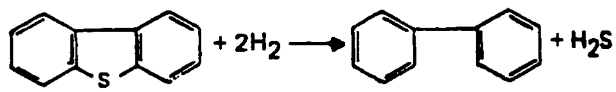
Hydrotreating or hydrodesulfurization (HDS) processes are used to produce oil fuels substantially reduced in sulfur, nitrogen and ash content. They are chemical processes, which involve contact of the oil with a catalyst and hydrogen to convert much of the chemically-bonded sulfur and nitrogen to gaseous hydrogen sulfide (H_2S) and ammonia (NH_3). These gases are separated from the fuel and then collected.

4.3.3.1 Process Description. In a typical hydrotreating process, oil to be treated is filtered to remove rust, coke and other suspended material. The oil is then mixed with hydrogen, heated to 340° to 450°C (650° to 850°F), and passed over one or more catalytic reaction beds. The most widely-used catalysts are composites made up of cobalt oxide, molybdenum oxide, and alumina, where alumina is the support and the other agents are promoters.[134]

Numerous chemical reactions occur which lead to removal of most of the sulfur as H_2S. Table 4.3-2 illustrates some of the types of compounds and reactions involved.[135] In an HDS process, hydrogen also reacts with other species besides sulfur compounds. For example, nitrogen compounds break down to liberate ammonia from the oil. This is referred to as denitrogenation or denitrification. Nickel and vanadium in the oil, which are bound as organo-metal compounds, are also liberated by reaction with hydrogen. This is generally referred to as demetallization. Most of the liberated metals deposit (as the sulfide) on the catalyst surface or in its pores and slowly deactivate the catalyst. Other reactions which take place break up large complex molecules such as asphaltenes and lead to a reduction in carbon residue for the product oil.

Many companies are engaged in developing and using catalytic hydrotreating or hydrodesulfurization processes. All are similar in basic concept and vary only in specifics such as the type of catalyst employed, the process conditions, and the process complexity. Figure 4.3-2 represents a simplified flow diagram of an HDS process currently being commercially marketed. Its basic elements are a feed filter, a heater, a single-stage catalytic reactor, a gas/liquid separator, a fractionating column, and a gas treatment section. This simple system is capable of producing fuel oil of approximately 1 percent sulfur from a feedstock such as atmospheric residual oil containing 2 percent sulfur. To produce a lower sulfur content product, additional catalytic reaction stages must be added. A system with two catalytic reaction stages can produce a fuel of approximately 0.3 percent sulfur content from a 2 percent sulfur feedstock. A more advanced process

Table 4.3-2. CHEMISTRY OF HYDRODESULFURIZATION REACTIONS IN PETROLEUM CRUDE OIL[136]

Name	Structure	Typical reaction
Thiols (mercaptans)	R–SH	R–SH + H_2 ⟶ RH + H_2S
Disulfides	R–S–S–R'	R–S–S–R' + $3H_2$ ⟶ RH + R'H + $2H_2S$
Sulfides	R–S–R'	R–S–R' + $2H_2$ ⟶ RH + R'H + H_2S
Thiophenes		
Benzothiophenes		
Dibenzothiophenes		

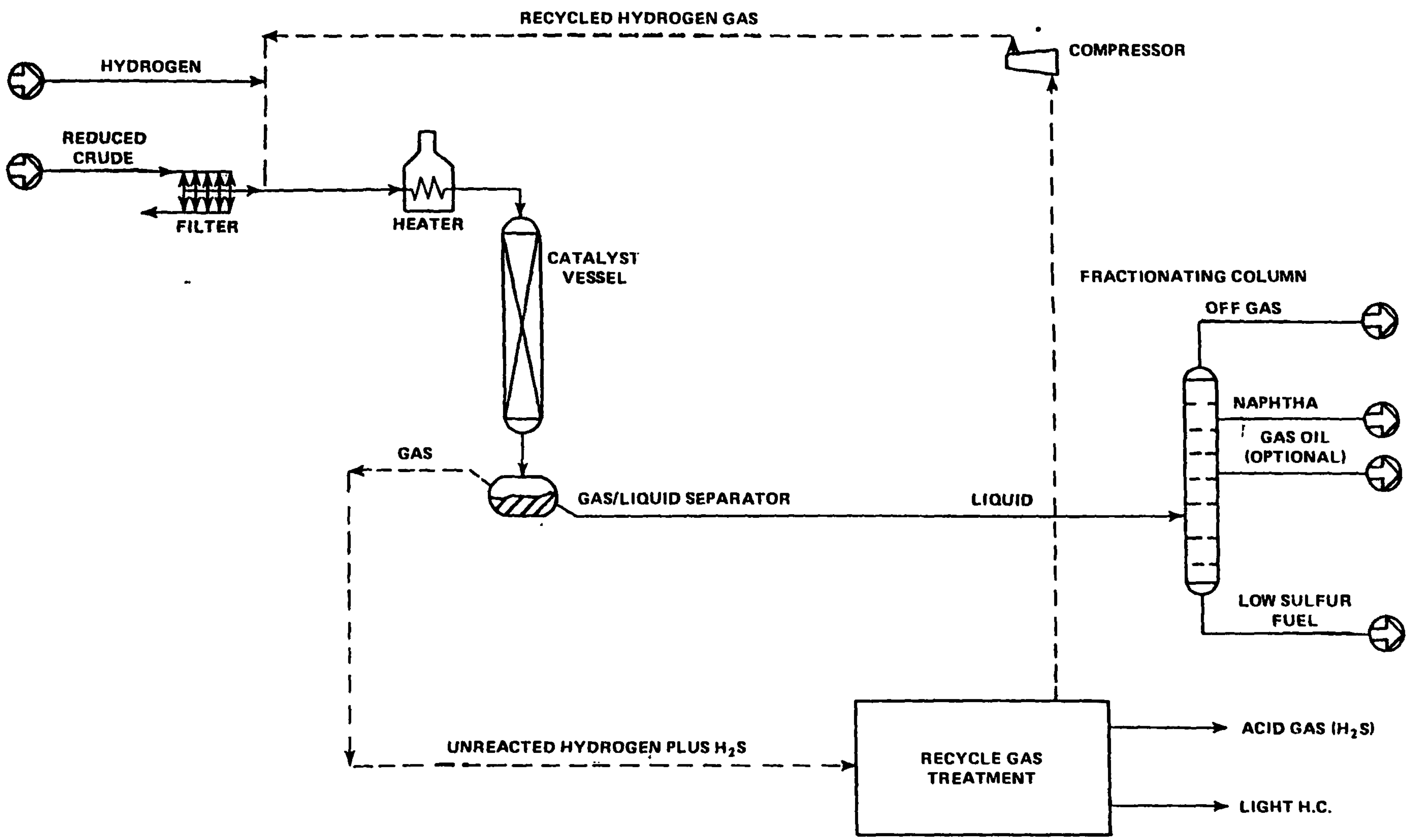


Figure 4.3-2. Basic HDS process.[137]

using three catalytic reactors can produce fuel oils with sulfur contents as low as 0.1 percent.[137]

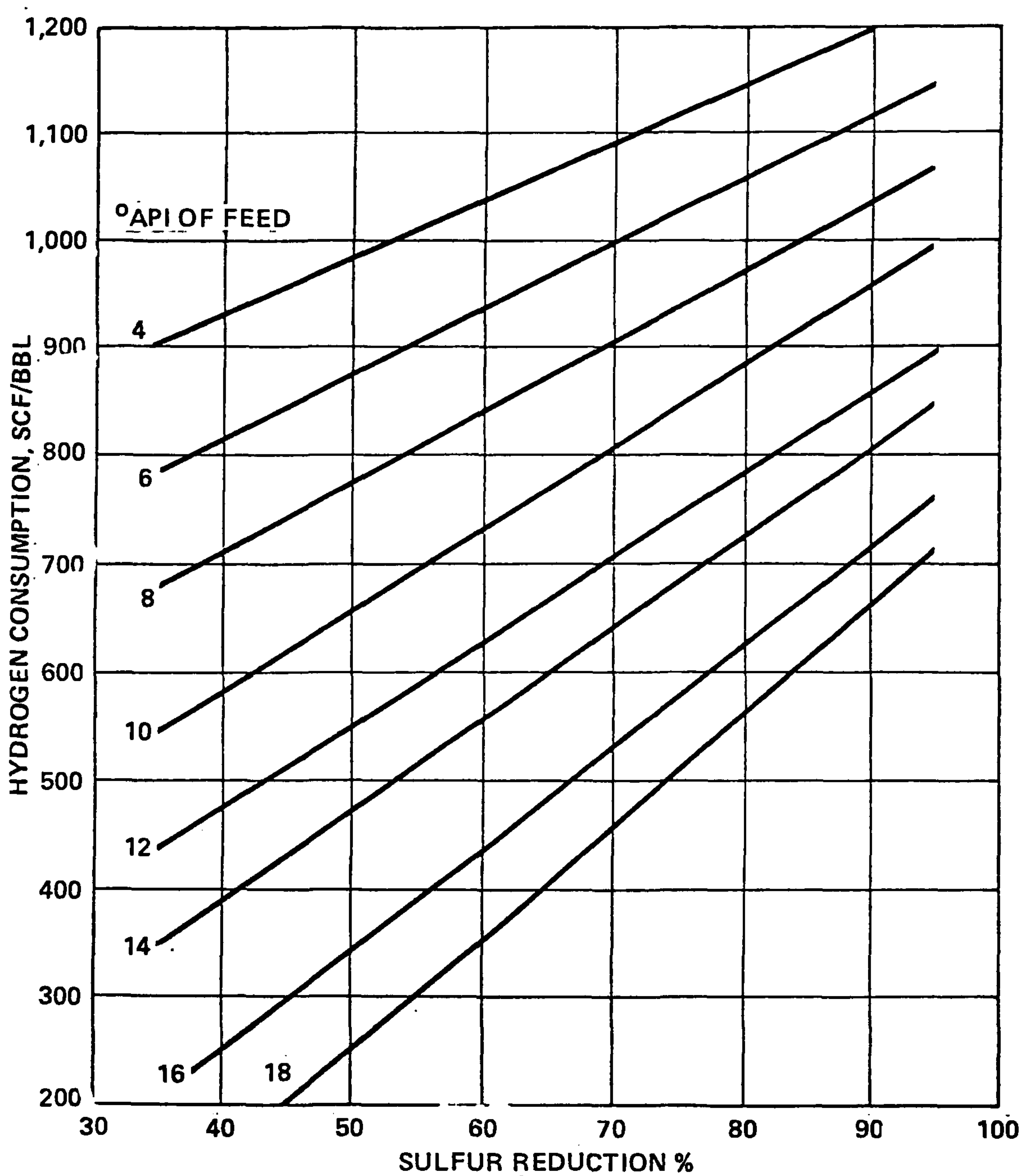
4.3.3.2 Development status. Over 30 hydrotreating processes are actively in use, and more than 250 processes have been described in the patent literature since 1970.[138] Many of these processes have been in commercial existence for over 10 years. The particular process selected by a refinery depends on the existing or planned refinery products. In existing facilities, a fuel desulfurization process is usually chosen to minimize modification or retrofit and/or satisfy refinery product mix goals and feedstock purchase expectations. Hence, the desulfurization process selected depends on the required sulfur content of the product and the feedstock properties.

4.3.3.3 Applicability to Nonfossil Fuel Fired Boilers. Like LSFO produced from naturally occurring low sulfur crude, oil that has been treated by an HDS process is readily applicable to all boiler types and sizes that burn a similar grade of fuel. Use of this cleaned oil should not adversely affect the operation of the boiler. In fact, boiler performance may even be improved due to the potential for less corrosion and deposit formation in the boiler due to the chemical composition changes in the oil as a result of hydrotreating.[139]

4.3.3.4 Factors Affecting Performance. The composition of the feedstock to a hydrotreater strongly influences the amount of hydrogen and catalyst consumption in the process. Major feedstock variables are density (expressed as °API), sulfur content, and metals content.

Hydrogen consumption has been correlated with sulfur reduction for a variety of residual oil feeds. Figure 4.3-3 illustrates these results on feedstocks varying from 4 - 18° API gravity. It can be seen that to obtain 90 percent reduction in sulfur for a 18° API feedstock, about 0.1 Nm^3 of hydrogen are consumed per liter of oil processed (650 scf/barrel); whereas, a 4° API feed would require 0.2 Nm^3/liter (1200 scf/barrel).[141]

As previously discussed, removal of metals by hydrotreating results in their deposition on the catalyst surface or in the pores. This leads to deactivation of the catalyst, which is only overcome by a temperature or



NOTE: 1. REDUCE BY 9% FOR FIXED-BED PROCESSES.
2. APPLY CORRECTION FOR HIGH-METALS FEEDS.

Figure 4.3-3. Hydrogen consumption in desulfurization of residual oil.[140]

pressure increase to maintain acceptable processing rates. The increase in required severity of process conditions leads to more hydro- cracking with a subsequent increase in hydrogen consumption.[142] A further complication from the metals content of the feed is a shortening of catalyst life. Even though some deactivation can be tolerated, the resultant increase in hydrogen uptake means the catalyst must be changed out more frequently.

The effect of metals is shown in Figure 4.3-4. This figure shows that for 90 percent sulfur removal from a 25 ppm metals content feedstock, about 27 barrels of oil can be processed per pound of catalyst; to achieve the same sulfur removal with a 100 ppm metals content feedstock, only 4.5 barrels can be processed per pound of catalyst; a feedstock containing 300 ppm metals requires almost 1 pound of catalyst per barrel. Clearly, high metal feedstocks are a problem to the refiner. Therefore, many refiners are using a separate stage of lower cost catalyst material prior to the special hydrodesulfurization catalysts. These separate stages may be packed with a material such as alumina or clay, which collects the metals and "guards" the subsequent high activity catalyst. For this reason, some refiners refer to this stage as a "guard reactor" or "guard vessel".[144]

4.4 CONTROL TECHNIQUES FOR NITROGEN OXIDES

As described in Chapter 3, emissions of nitrogen oxides (NO_x) from nonfossil fuel fired boilers are usually lower than NO_x emissions from fossil fueled boilers. The lower combustion temperatures in nonfossil fuel fired boilers reduce the formation of NO_x from the reaction of atmospheric nitrogen and oxygen, while the lower nitrogen content of some nonfossil fuels reduces the formation of "fuel NO_x." Emissions of NO_x from boilers cofiring nonfossil fuels and fossil fuels approach the level of emissions from fossil fuel boilers as the firing proportion of fossil fuel increases.

Because of the lower NO_x emissions, NO_x controls have not been applied to nonfossil fuel boilers. Limited testing of two combustion modifications (lower excess air and staged combustion) on boilers co- firing wood and coal or gas showed possible reductions of NO_x due to these techniques.[145] However, comprehensive test data substantiating the performance of NO_x

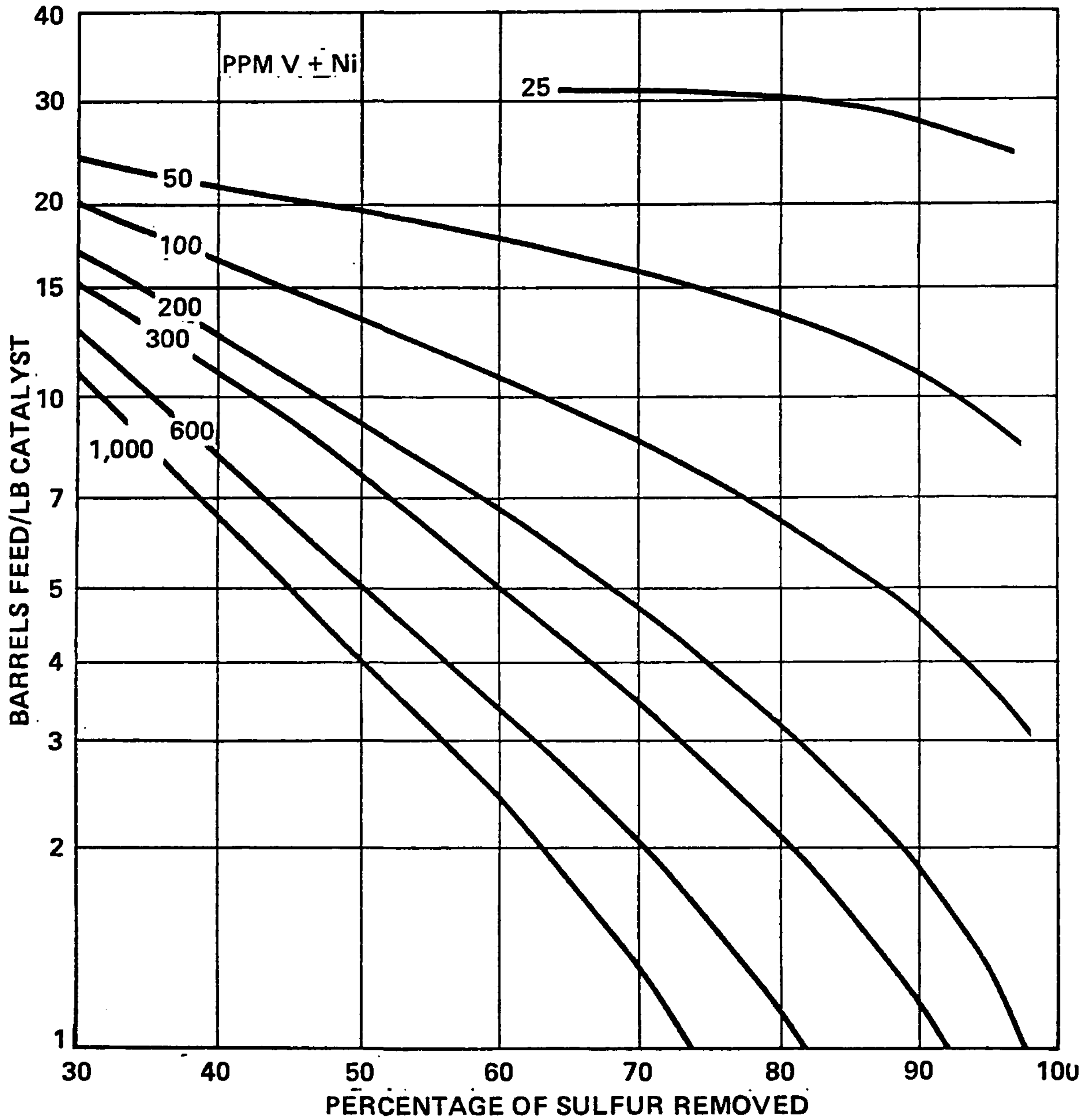


Figure 4.3-4. Effect of metals content on catalyst consumption.[143]

controls over the range of boiler types, firing conditions, and fuel types are not available. Thus, NO_x controls will not be considered further in this document. NO_x control techniques generally applicable to fossil fuel fired boilers include:

- low excess air
- staged combustion
- flue gas recirculation
- low NO_x burners
- eliminated or reduced combustion air preheat
- ammonia injection

General discussions of these techniques can be found in the Technology Assessment Report for Industrial Boiler Applications: NO_x Combustion Modifications.[146]

4.5 EMISSION TEST DATA FOR MOST EFFICIENT EMISSION CONTROL TECHNOLOGIES

This section summarizes test data for the most efficient particulate control technologies applied to nonfossil fuel fired boilers operated near capacity. These data were previously presented in Section 4.1.6 with the rest of the emission test data and thus met the following criteria (detailed in Appendix C):

- the test was conducted in accordance with EPA Method 5 procedures,
- the boiler type and rated steam capacity are known,
- the fuel type is known, and
- critical emission control system operating parameters are known such as flue gas pressure drop for wet scrubbers, air-to-cloth ratio for fabric filters, and specific collection area for electrostatic precipitators.

The test data in this section also meet two additional criteria:

- the test data represent the most efficient control technologies in use for each fuel type,
- the boiler was operated at 75 percent or more of the rated steam capacity, and
- the boiler and control system were operated within the design limits of the system.

4.5.1 Emission Test Data For Wood And Wood/Fossil Fuel Fired Boilers

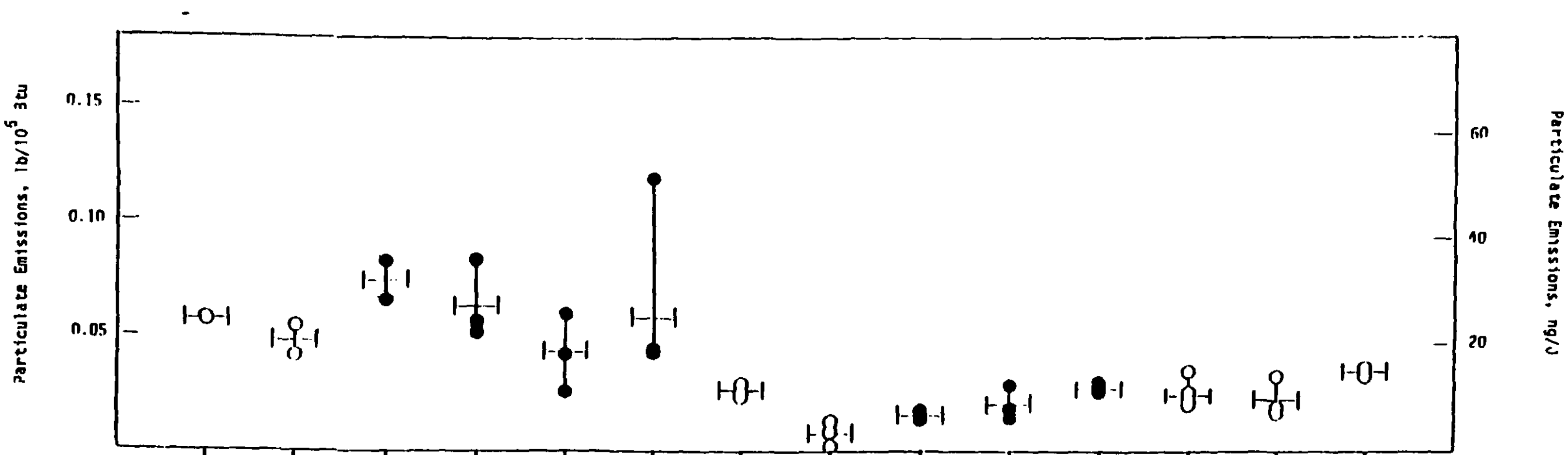
Figure 4.5-1 presents emission test data for the most efficient particulate control technologies in use on wood-fired and wood/fossil fuel cofired boilers. For wood-fired boilers, the most efficient systems of emission control are ESPs, adjustable throat venturi scrubbers, fabric filters, and EGBs. Venturi scrubbers without mist eliminators are not considered to be most efficient systems of control unless once through scrubber liquor is used to reduce the carry over of particulate matter in the scrubber liquor. Tests AJ2 and AJ4 are also not included because of the high excess air levels shown during testing which affected the scrubber outlet emission levels (see Section 4.1.6.1.2). Test runs 8,11,12 and 14 for the group of test labeled BE3 through BE6 are not shown since the design inlet loading to the EGB was exceeded.

4.5.2 Particulate Matter Emission Test Data For Bagasse-Fired Boilers

Figure 4.5-2 presents emission test data for the most efficient particulate control technologies in use on bagasse-fired boilers. These data include five boilers controlled by low pressure drop wet scrubbers and show emission levels of 130 ng/J (0.30 lb/10^6 Btu) or less. Boilers with 2 parallel wet scrubbers are not considered as most efficient controls available because of the problems discussed in Section 4.1.6.2

4.5.3 Emission Test Data For MSW- And RDF-Fired Boilers

Figure 4.5-3 presents emission test data for the most efficient particulate control technology in use on MSW- and RDF-fired boilers. These data are for boilers controlled by ESPs with SCAs of 47 $m^2/(m^3/s)$ (240 ft^2/1000 acfm) or more. As shown in the figure, ESPs with SCAs in this range show emission levels below 43 ng/J (0.10 lb/10^6Btu).



Test #	AJ5	AA1	AK2	AK3	BI1	BH6	BJ1	BH7	BD2	BC2	BE2[m]	BE3[n]	BE4[n]	BE5[n]
Boiler #	-	-	-	-	7/8[c]	4/5[d]	-	4/5[d]	-	1,2,3[j]	11	11	11	11
Boiler Type	SS	SS	SS	SS	SS/SS	PC/SS	SS	PC/SS	SS	DO	SS	SS	SS	SS
Design Capacity (10^3 lb/hr steam)	110	150	135	135	240/325	140/200	600	140/200	25	3x50	400	400	400	400
Nonfossil Fuel Type	B,S	HF	B,S	B,S	B/B	-/B	B,S	-/B	B	SHF	HF	HF	HF	HF
% Heat Input[h]	100	100	100	100	25/25	-/100	64	-/80	100	100	100	100	100	100
% Ash (dry)	-	2-8[l]	1.7	4.2	3.4	4.4	-	-/5.9	5.1	3.4	9.4[k]	3.8	3.8	4.8
% Moisture	-	60-65[l]	45	45	46	42	-	-/28	47	57	56[k]	49	50	58
Other Fuel	-	-	-	-	LSC/LSC[e]	LSC/[f]-	HSO	LSC/LSC[g]	-	-	-	-	-	-
Load Factor - %[h]	91	95	94	100	87/87	48/88	76	84/46	75	91	96	101	116	95
% O_2 in flue gas[h]	8.8	7.3	14.5	11.8	10.2	12.5	6.2	9.9	9.9	10.7	9.6	7.9	7.2	8.1
Control Device	MC/WS	MC/WS	MC/WS	MC/WS	MC/ESP	MC/ESP	MC/ESP	MC/ESP	MC/FF	MC/FF	MC/EGB	MC/EGB	MC/EGB	MC/EGB
Operating Parameter[h,i]	15.2	18	20	26	320	452	456	600	3.66	2.98	6.0	3.4	4.0	5.6
Design Parameter[i]	-	-	-	-	296	460	356	460	4.10	3.64	-	-	-	-
Fly Ash Reinjection	Y	Y	Y	Y	Y	N/Y	Y	N/Y	N	N	Y	Y	N	Y
Sand Classification	Y	Y	Y	Y	N	N/N	Y	N/N	N	N	Y	Y	N	Y

Figure 4.5-1. Particulate Emissions from Wood-Fired and Wood/Fossil Fuel Cofired Boilers with High Efficiency Controls.[a,b]

Footnotes for Figure 4.5-1:

[a]All data were obtained by EPA Method 5 and meet established criteria for acceptability. The key for the data is:

SS - spreader stoker
PC - pulverized coal
DO - dutch oven
B - bark
S - sawdust or shavings
SD - sanderdust
HF - hog fuel (wood/bark mixture)
SHF - salt-laden hog fuel
LSC - low sulfur coal
HSO - high sulfur residual oil
WS - wet scrubber
MC - mechanical collector
ESP - electrostatic precipitator
FF - fabric filter
EGB - electrostatic gravel bed filter
Y - yes
N - no
O - EPA-5 data acquired in industry tests
● - EPA-5 data acquired in EPA tests
├─┤ - average

[b]More detailed information on the emission test data and the data sources may be found in Appendix C.

[c]The flue gas from boilers 7 and 8 passes through individual mechanical collectors. It is then combined into a single duct and then split to enter a two chamber ESP with two stacks. The emission levels shown are the weighted average of both stacks.

[d]The flue gas from boilers 4 and 5 passes through individual mechanical collectors. It is then combined into a single duct and then split to enter two separate ESPs in parallel. The emission levels shown are the weighted average of both stacks.

[e]The analysis of the coal showed the following composition: Moisture - 5.5%; ash (dry) - 12.4%; sulfur (dry) - 0.86%.

[f]The analysis of the coal showed the following composition: Mositure 3.9%; ash (dry) - 7.1%; sulfur (dry) - 0.7%.

[g]The analysis of the coal showed the following composition: Moisture - 3.2%; ash (dry) - 17.7%; sulfur (dry) - 0.56%.

[h]Average value during testing.

[i]For ESPs this value is specific collection area in ft^2/1000 acfm; for fabric filters this value is air to cloth ratio in ft/min; for wet scrubbers and the EGB this value is pressure drop in inches of water.

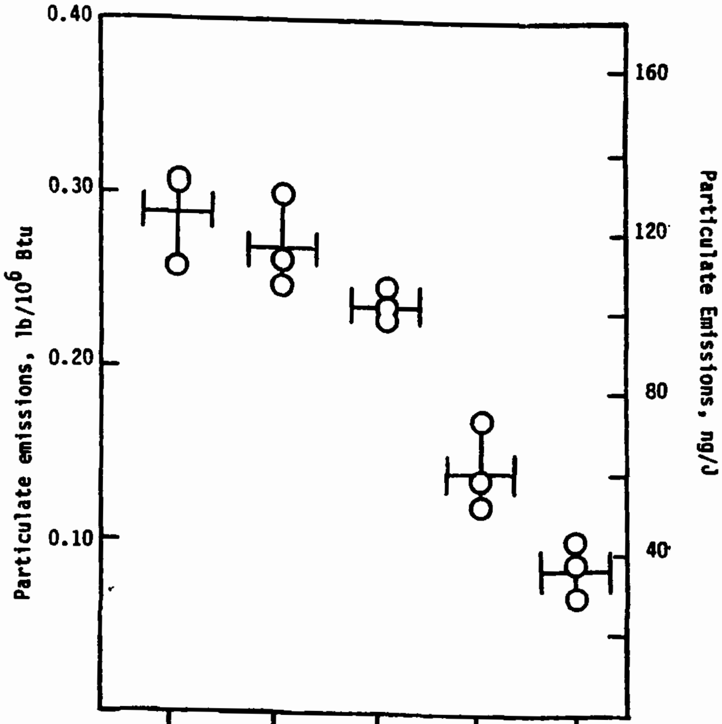
[j]The flue gas from boilers 1,2 and 3 passes through individual mechanical collectors. It is then combined into a single duct prior to entering the fabric filter.

[k]At this facility char from the first stage of the mechanical collector is slurried and separated by screens into large and small fractions. The large char fraction is mixed with the hog fuel. These values represent an analysis of the mixture of char and hog fuel.

[l]These data did not come from an analysis done during emission testing. They were obtained from industry sources and are representative of the typical fuel burned at this facility.

[m]The EGB has three modules, each of which cleans one-third of the flue gas. Each module has a separate stack. The emission levels shown are the weighted average of all three stacks.

[n]Emissions are from the outlet of module 3 of the EGB.



Test #	DE1	DE2	DE3	DH1	DC1
Boiler #	6	12	14	5	-
Boiler Type	FC	SS	SS	SS	SS
Design Capacity - (10^3 lbs/hr steam)	125	150	150	200	312
Bagasse Characteristics-					
% Heat Input[c]	94	100	100	100	100
% Ash(dry)	-	-	-	-	3.3
% Moisture	-	-	-	-	48
Other fuel	HSO	-	-	-	-
Load Factor - %[c]	96	92	98	82	93
% O_2 in flue gas[c]	11.0	4.8	5.9	10.5	7.1
Control Device	WS	MC/WS	MC/WS	WS	MC/WS
Operating Parameter - ΔP[c] (in. w.c.)	6	6	6	6	2[d]

Figure 4.5-2. Particulate Emissions form Bagasse-Fired Boilers with High Efficiency Controls.[a,b]

Footnotes to Figure 4.5-2:

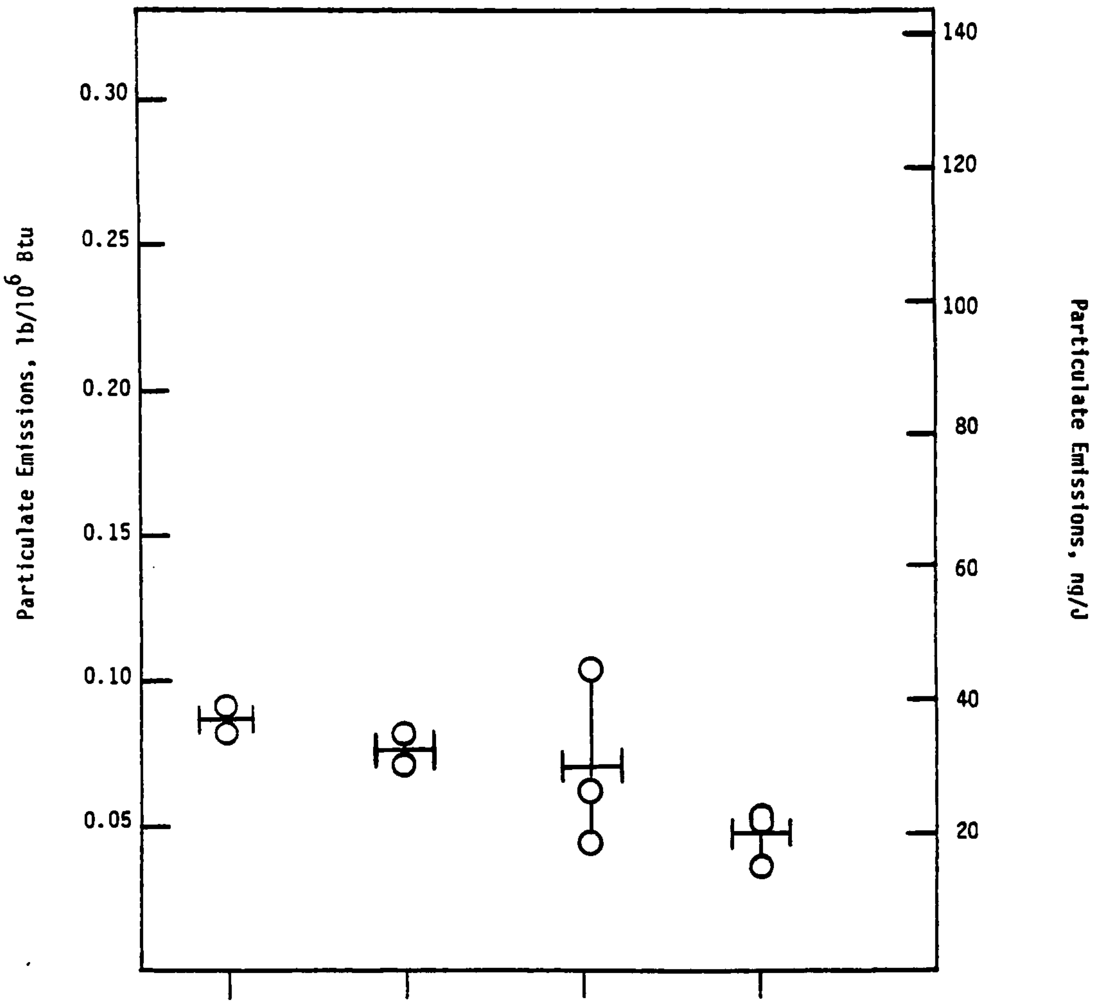
[a]All of the data were obtained by EPA Method 5 and meet established criteria for acceptability. The key for the data is:

HS - horseshoe
FC - fuel cell
SS - spreader stoker
HSO - high sulfur residual oil
MC - mechanical collector
WS - wet scrubber
P - pressure drop
O - EPA-5 test data acquired in industry tests.
● - EPA-5 test data acquired in EPA tests.
|—| - average

[b]More detailed information on the emission test data and the data sources may be found in Appendix C.

[c]Average value during testing. For all the wet scrubbers tested the scrubber pressure drop is assumed to be equal to the reported design value. The pressure drops were not actually measured during testing.

[d]This wet scrubber is an ejector venturi design, therefore the gas phase pressure drop is not a good indicator of scrubber efficiency. This scrubber would be approximately equivalent to a "standard" venturi with a pressure drop of 1.5 kPa (6 inches w.c.).



Test #	FC1	FE2	HF1	FB1
Boiler Type	OF	OF	SS	OF
Design Capacity (10^3 lbs/hr steam)	175/175[c]	110	200	135
Nonfossil Fuel Type	MSW	MSW	RDF[e]	MSW
% Heat Input[d]	100	100	100	100
Load factor - %[d]	80/88	79	80	77
% O_2 in flue gas[d]	9.9	9.4	7.8	9.2
Control Device	ESP	ESP	MC/ESP	MC/ESP
Operating Parameter SCA[d] (ft^2/1000 acfm)	243	278	326	573
Design Parameter - SCA (ft^2/1000 acfm)	209	154	248	316

Figure 4.5-3. Particulate Emissions from MSW- and RDF-fired Boilers with High Efficiency Controls.[a,b]

Footnotes for Figure 4.5-3:

[a]All of the data were obtained by EPA Method 5 and meet established criteria for acceptability. The key for the data is:

OF - overfeed stoker
SS - spreader stoker
ESP - electrostatic precipitator
MSW - municipal solid waste
MC - mechanical collector
SCA - specific collection area
O - EPA Method 5 data acquired in industry tests
|—| - average

[b]More detailed information on the emission test data and the data sources may be found in Appendix C.

[c]Two boiler/ESPs are exhausted through a common stack; each boiler has a steam generating capacity of 175,000 lb/hr.

[d]Average value during testing.

[e]Although fuel samples were not taken during testing, industry sources report that the typical RDF fired at this facility contains 16.2 percent ash on a dry basis and 51 percent moisture. The RDF is produced by a wet pulping process.

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5. MODIFICATION AND RECONSTRUCTION

Standards of Performance are applicable to facilities whose construction, modification, or reconstruction commenced after proposal of the standards. Such facilities are termed "affected facilities." Standards of performance are not applicable to "existing facilities" which are facilities whose construction, modification, or reconstruction commenced on or before proposal of the standards. However, an existing facility may become an affected facility and therefore subject to standards, if the facility undergoes modification or reconstruction.

Modification and reconstruction are defined under 40 CFR 60.14 and 60.15, respectively. The definition of commenced appears in 40 CFR 60.2(i). Modification and reconstruction provisions are summarized in Section 5.1 of this chapter. Section 5.2 discusses the applicability of the provisions to nonfossil fuel fired boilers.

5.1 SUMMARY OF MODIFICATION AND RECONSTRUCTION PROVISIONS

5.1.1 Modification

With certain exceptions, any physical or operational change to an existing facility that would result in an increase in the emission rate to the atmosphere of any pollutant to which a standard of performance applies would be considered a modification within the meaning of Section 111 of the Clean Air Act. Modification determinations are made on a case-by-case basis. The key to a modification determination is whether total emissions to the atmosphere (expressed in kg/hr) from the facility as a whole have increased as a result of the change. For example, if the affected facility is defined as a group of pieces of equipment, then the aggregate emissions from all the equipment must increase before the facility will be considered modified.

Exceptions which allow certain changes to an existing facility without it becoming an affected facility, irrespective of an increase in emissions are listed below.

1. Routine maintenance, repair, and replacement.
2. An increase in production rate without a capital expenditure (as defined in 40 CFR 60.2(bb)).
3. An increase in the hours of operation.
4. Use of an alternate fuel or raw material if, prior to the standard, the existing facility was designed to accommodate that alternate fuel or raw material.
5. The addition or use of any system or device whose primary function is the reduction of air pollution, except when an emission control system is removed or is replaced by a system determined by EPA to be less environmentally beneficial.
6. Relocation or change in ownership of the existing facility.

Once an existing facility is determined to be modified, all of the emission sources of that facility are subject to the standards of performance for the pollutant whose emission rate increased and not just the emission source which displayed the increase in emissions. However, a modification to one existing facility at a plant will not cause other existing facilities at the same plant to become subject to standards.

An owner or operator of an existing facility who is planning a physical or operational change which may increase the emission rate of a pollutant to which a standard applies shall notify the appropriate EPA regional office 60 days prior to the change, as specified in 40 CFR 60.7(a)(4).

5.1.2 Reconstruction

An existing facility may also become subject to new source performance standards if it is determined to be "reconstructed." As defined in 40 CFR 60.15, a reconstruction is the replacement of the components of an existing facility to the extend that (1) the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost of a comparable new facility and (2) it is technically and economically feasible for the facility to meet the applicable standards. Because EPA considers reconstructed facilities to constitute new construction rather than modification, reconstruction determinations are made irrespective of changes in emission rate. Determinations are made on a case-by-case basis. If the facility is determined to be reconstructed, it must comply with all of the provisions of the standards of performance applicable to that facility.

If an owner or operator of an existing facility is planning to replace components and the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost of a comparable new facility, the owner or operator shall notify the appropriate EPA regional office 60 days before the construction of the replacements commences.

5.2 APPLICABILITY OF MODIFICATION AND RECONSTRUCTION PROVISIONS TO NONFOSSIL FUEL FIRED BOILERS

5.2.1 Modification

Actions which may increase emissions and therefore may be considered modifications include changes in the type of fuel fired and changes in the boiler components. These changes are discussed below.

5.2.1.1 Fuel Switching. The combustion of an alternate fuel will not be deemed a modification so long as an existing boiler was designed to accommodate the alternate fuel as discussed in 40 CFR 60.14(e)(4). Any other switch in fuel which increases the emissions of a regulated pollutant will constitute a modification, with the exception of fuel switches described in Section 111(a)(8) of the Clean Air Act and those specifically excluded by the standard.

5.2.1.2 Physical and Operational Changes. Physical changes could be made to almost every component of a nonfossil fuel fired boiler. This section highlights some of the changes which may result in emissions increases.

Combustion Air System. The air flow in a boiler's draft system can be increased by changing fans and air nozzles in order to correct combustion problems and to reduce tubing corrosion. This change could result in greater excess air and higher air velocities which in turn could increase PM emissions. Other changes in air flow include altering the ratio of air added over (overfire air) and under (underfire air) the grates. Increasing the velocity of underfire air may also result in increased PM carryover.

Flue Gas Handling System. Alterations can be made in the flue gas handling system by adding an economizer and/or air heater, or by replacing the primary fan. The addition of an economizer would not affect the emission rate of any pollutant and thus would not be termed a modification. The addition of an air heater, however, could increase furnace temperatures and NO_x formation. The likelihood of an owner/operator installing an air heater is high.[1]

Fly Ash Reinjection. A system to reinject fly ash or unburned carbon particulate matter from stoker-fired boilers can be added to improve the overall fuel combustion efficiency and reduce overall operating costs. Fly ash reinjection increases the boiler particulate loading and therefore may increase emissions. Rapidly rising fuel costs tend to make this alternative more attractive and may căuse some existing facilities to either add reinjection systems or increase reinjection rates in the future.[1]

5.2.2 Reconstruction

In a reconstruction determination, when components are replaced as part of a maintenance program the capital expenditures for each component are first adjusted by the annual asset guideline repair allowance percentage (Internal Revenue Service Publication 534) as specified in 40 CFR 60.2(bb). Replacement of single boiler components would not likely require sufficient capital to subject an existing facility to the reconstruction provisions. On the other hand, replacement of groups of components (e.g., retubing and rebricking) may result in sufficient expenditures to subject the facility to these provisions. However, it does not appear likely that existing boilers with normal repair and maintenance practices will become affected facilities by virtue of the reconstruction provision.

While there is a difference between the terms "repair" and "maintenance", they are most often considered together in available cost information. The National Board Inspection Code does, however, distinguish between repair and maintenance and as an example, defines repairs as the following items:[2]

- Replacement of sections of boiler tubes, provided the remaining part of the tube is not less than 75 percent of its original thickness.
- Seal welding of tubes.
- Building-up of certain corroded surfaces.
- Repairs of cracked ligaments of drums or headers within certain definite limits.

The types of maintenance that will usually require substantial amounts of time are boiler cleaning and repair or replacement of various parts. Primary maintenance areas for solid fuel fired boilers are the fuel feed system and the fuel firing mechanism.

5.2.3 Summary

Modification and reconstruction determinations are made on a case-by-case basis. It appears that the reconstruction provisions will probably not cause an existing boiler to be reclassified as an affected facility. However, there are boiler modifications which could result in an existing boiler becoming classified as an affected facility subject to new source performance standards. Addition of a fly ash reinjection system or of an air preheater is indicated as likely from contacts with industry personnel. In addition some fuel switching is anticipated. An existing facility which makes any of these changes is potentially a modified facility.

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6. MODEL PLANTS AND EMISSION CONTROL OPTIONS

The impacts of various emission control requirements on nonfossil fuel fired boilers (NFFBs) are determined through an analysis of "model boilers." Model boilers are standard boilers (which represent the new NFFB population) in combination with emission control techniques. The model boiler evaluation provides a boiler-specific analysis of the economic, environmental, and energy impacts resulting from the application of different emission control techniques to the standard boilers.

The selection of model boilers involves basically a three-step approach as illustrated in Figure 6-1. The first step is to select the standard boilers and fuel types. The rationale behind these selections is discussed in Section 6.1. The second step, discussed in Section 6.2, involves specifying emission control levels based on the control performance data in Chapter 4 and identifying control technologies that will meet these levels. The last step, discussed in Section 6.3, combines the standard boilers and selected control technologies into a set of model boilers. Finally, numerical emission limits and standard boilers for each fuel type and control level are presented in Section 6.4.

6.1 SELECTION OF STANDARD BOILERS

Standard boilers are selected to represent the new NFFB population. Factors used in their selection include fuels, firing methods, and boiler distribution by capacity. A summary of the standard boilers selected for evaluation is presented in Table 6-1. The selection rationale is presented in Section 6.1.1. A complete description of the standard boilers is found in Sections 6.1.2 and 6.1.3.

6.1.1 Selection Rationale

The boiler capacities, firing methods, and fuels reflected in the standard boilers represent current and future designs based on the NFFB population data presented in Chapter 3. The principal NFFB fuels are wood

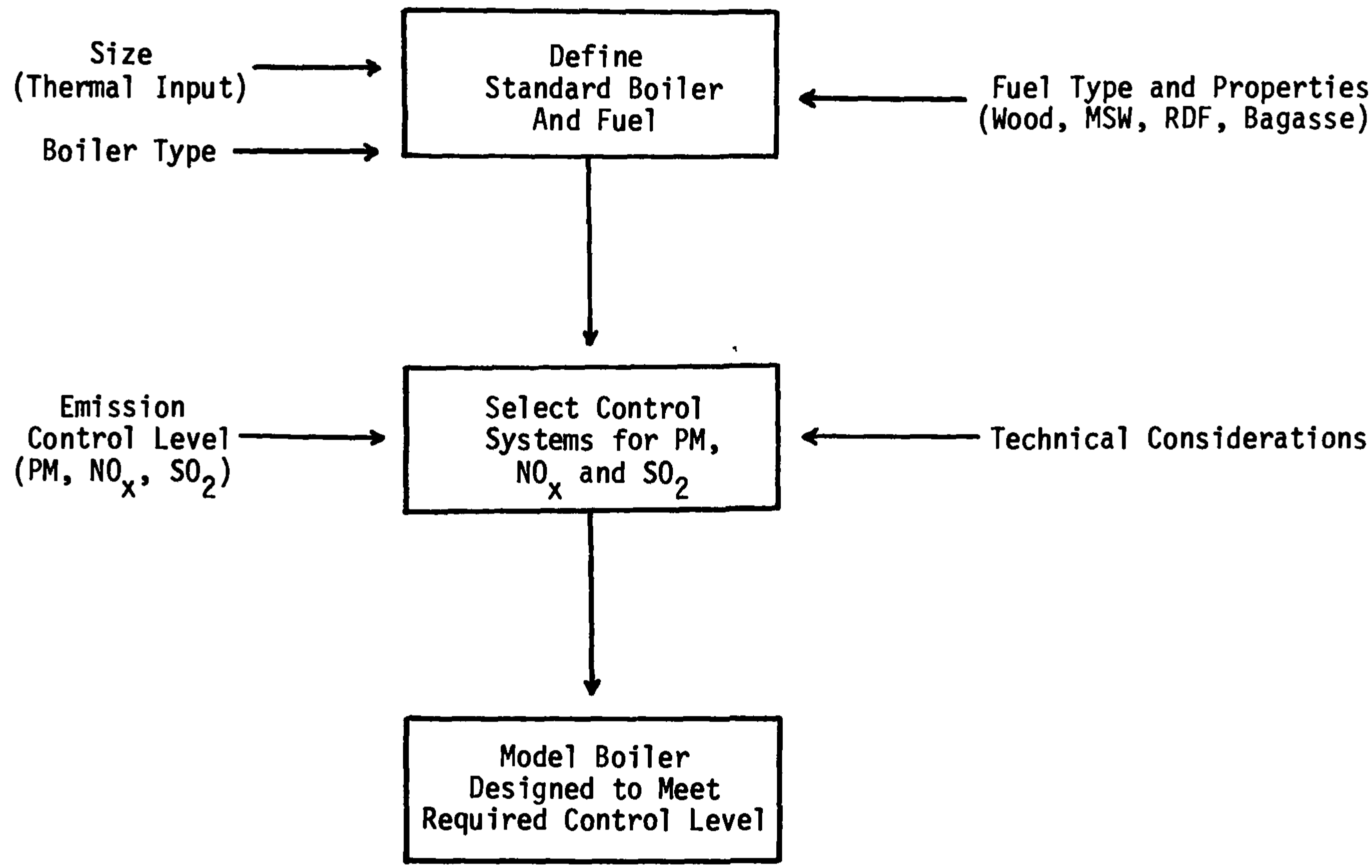

Figure 6-1. Model Boiler Selection Logic Diagram

TABLE 6-1. STANDARD BOILERS SELECTED FOR EVALUATION

Boiler Type[a]	Fuel[b]	Heat Input MW	Heat Input (10^6 Btu/hr)
Spreader Stoker	Wood	8.8	(30)
Spreader Stoker	Wood	22	(75)
Spreader Stoker	Wood	44	(150)
Spreader Stoker	Wood	117	(400)
Spreader Stoker	HAB	44	(150)
Spreader Stoker	SLW	44	(150)
Spreader Stoker	75% Wood/[c] 25% HSE	44	(150)
Spreader Stoker	50% Wood/[c] 50% HSE	44	(150)
Spreader Stoker	50% Wood/[c] 50% HSE	117	(400)
Spreader Stoker	50% Wood/[c] 50% LSW	44	(150)
Spreader Stoker	50% RDF/[c] 50% HSE	44	(150)
Controlled Air	MSW	2.9	(10)
Mass Burn	MSW	44	(150)
Mass Burn	MSW	117	(400)
Spreader Stoker	Bagasse	58.6	(200)

[a]Descriptions and diagrams of these boiler types are contained in Chapter 3.

[b]Wood - hog fuel (wood/bark mixture)
HAB - high ash bark
SLW - salt-laden wood
HSE - high sulfur eastern coal
LSW - low sulfur western coal
RDF - refuse derived fuel
MSW - municipal solid waste

[c]Average fuel mixture on a heat input basis.

and bark waste, solid waste including municipal solid waste (MSW) and refuse derived fuel (RDF), and bagasse. Boilers are selected to represent each of these basic fuel types. Representative capacities within each fuel type are then selected within the range of expected capacities for the new NFFB population. Wherever practical, boiler capacities for the nonfossil fuel types were selected to be the same as those selected for fossil fuel fired boilers in the Background Information Document (BID) for industrial boilers.[1] Also, for cases involving cofiring of fossil and nonfossil fuels, the fossil fuels selected are the same as those used in the industrial boiler study. These selection criteria were applied to facilitate direct comparisons between the industrial boiler and nonfossil fuel fired boiler studies, and to allow comparison of the economic, environmental, and energy impacts resulting from alternative regulatory options.

As discussed in Chapter 3, capacities of NFFBs range from less than 2.9 MW (10 x 10^6 Btu/hr) to greater than 117 MW (400 x 10^6 Btu/hr) thermal input. Many boilers at the lower end of the capacity range are used for space heating, whereas the boilers at the upper end of the capacity range are generally used to produce process steam, to drive turbines, and in some cases, to generate electricity. In Table 6-2, the NFFB capacity range is segmented into five size categories with appropriate standard boilers chosen to represent each capacity interval. Figures 6-2 and 6-3 illustrate how the selected wood- and bagasse-fired boiler capacities compare with capacities of these types of boilers sold between 1970 and 1978. Insufficient sales data are available to provide similar comparisons for MSW- and RDF-fired facilities.

Wood-fired boilers exist in all five capacity intervals. However, the bulk of the wood-fired boiler capacity sold consists of watertube boilers larger than 7.3 MW (25 x 10^6 Btu/hr) thermal input. Sales data for these types of boilers are presented in Figure 6-2 and in Chapter 3. Smaller boilers are generally of the firetube design and are commonly used in the furniture industry. Similar sales data were not available for this type of boiler. The firing mechanisms for most new wood-fired boilers for which data are available are essentially the same, spreader or overfeed stoker,

TABLE 6-2. REPRESENTATIVE STANDARD BOILER CAPACITIES

	Capacity Range - Thermal Input				
Fuel[a]	<7.3 MW (<25 x 10^6 Btu/hr)	7.3-14.7 MW (25-50 x 10^6 Btu/hr)	14.7-29.3 MW (50-100 x 10^6 Btu/hr)	29.3-73.3 MW (100-250 x 10^6 Btu/hr)	>73.3 MW (>250 x 10^6 Btu/hr)
Wood		8.8 MW (30 x 10^6 Btu/hr)	22.0 MW (75 x 10^6 Btu/hr)	44.0 MW (150 x 10^6 Btu/hr)	117 MW (400 x 10^6 Btu/hr)
HAB				44.0 MW (150 x 10^6 Btu/hr)	
SLW				44.0 MW (150 x 10^6 Btu/hr)	
75% Wood/[b] 25% HSE				44.0 MW (150 x 10^6 Btu/hr)	
50% Wood/[b] 50% HSE				44.0 MW (150 x 10^6 Btu/hr)	117 MW (400 x 10^6 Btu/hr)
50% Wood/[b] 50% LSW				44.0 MW (150 x 10^6 Btu/hr	
50% RDF/[b] 50% HSE				44.0 MW (150 x 10^6 Btu/hr)	
MSW	2.9 MW (10 x 10^6 Btu/hr)			44.0 MW (150 x 10^6 Btu/hr)	117 MW (400 x 10^6 Btu/hr)
Bagasse				58.6 MW (200 x 10^6 Btu/hr)	

[a]Wood - hog fuel (wood/bark mixture)
HAB - high ash bark
SLW - salt-laden wood
HSE - high sulfur eastern coal
LSW - low sulfur western coal
RDF - refuse derived fuel
MSW - municipal solid waste

[b]Average fuel mixture on a heat input basis.

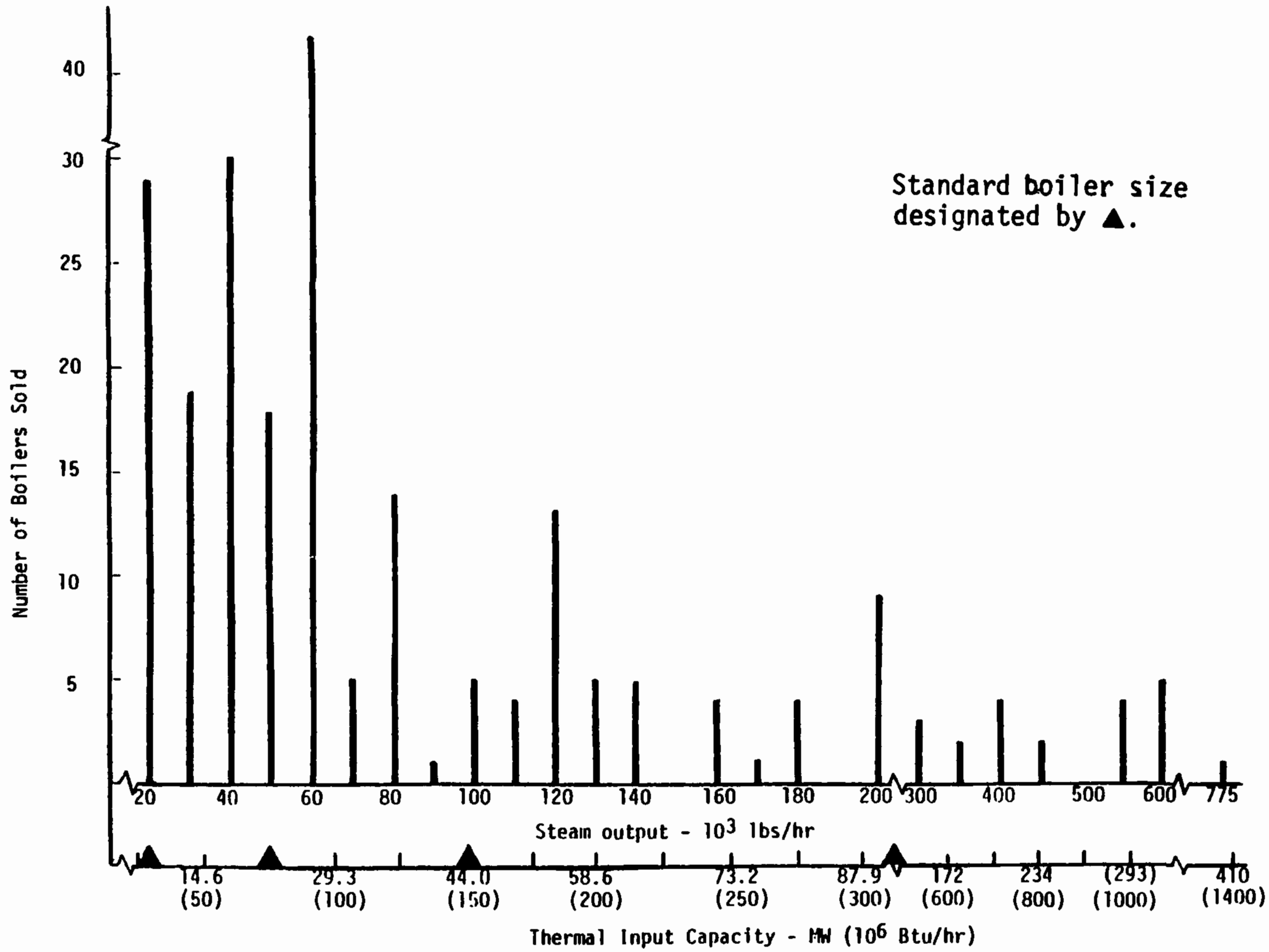

Figure 6-2. Size distribution of wood-fired watertube boilers sold from 1970 through 1978 together with the selected standard boiler sizes. (size distribution data from Chapter 3)

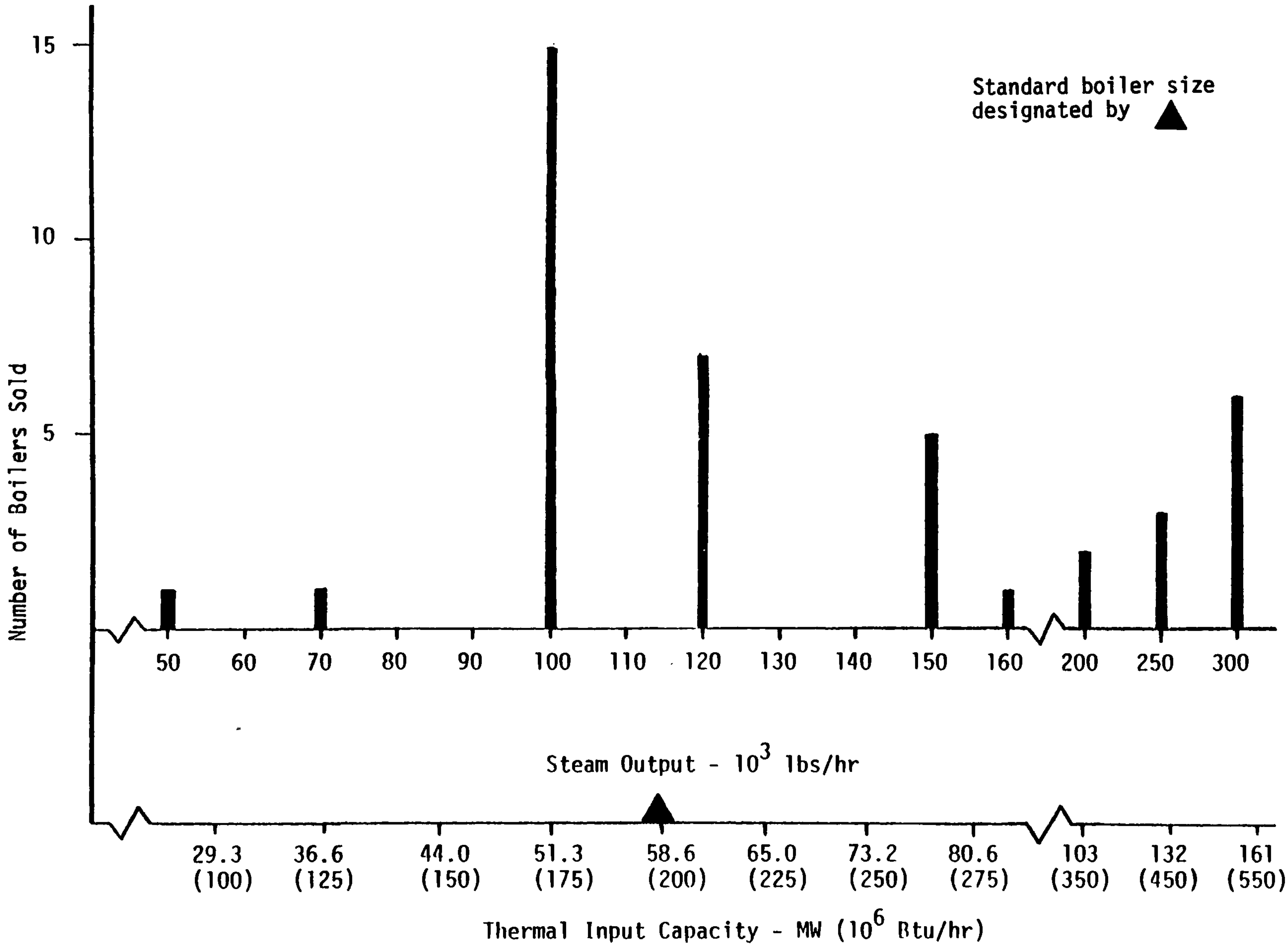

Figure 6-3. Size distribution of bagasse-fired watertube boilers sold from 1970 through 1978 together with the selected standard boiler size. (size distribution data from Chapter 3)

and emission rates, while variable, are similar across the entire capacity range. Four wood-fired boiler sizes of similar design were selected to show the regulatory impacts on various size boilers. These sizes are 8.8, 22, 44, and 117 MW (30, 75, 150, and 400 x 10^6 Btu/hr) thermal input. Fuels selected for these standard boiler sizes include a hog fuel representative of wood fuels fired in most wood-fired boilers in the United States. Two additional fuels were selected for the 44 MW (150 x 10^6 Btu/hr) boiler to show the sensitivity of regulatory impacts on wood-fired boilers to fuels containing additional ash or salt resulting from storage or from logging operations. These fuels were designated high ash bark (HAB) and salt laden wood (SLW).

Boilers that cofire wood and coal have firing mechanisms similar to wood-fired boilers but are uncommon in the smaller capacity intervals. As a result, two boilers were selected of the same capacities as the largest wood-fired boilers, 44 and 117 MW (150 and 400 x 10^6 Btu/hr). Coals selected for these standard boiler sizes include a high sulfur eastern coal (HSE) and a low sulfur western coal (LSW). Various fuel mixtures were selected for these standard boiler sizes. Wood/HSE mixtures averaging 50 percent wood were selected for each size boiler and a mixture averaging 75 percent wood was selected for the 44 MW boiler. Also selected for the 44 MW boiler was a wood/LSW mixture averaging 50 percent wood. Different fuel mixture ratios and coal sulfur contents were selected to show the effect of these variables on SO_2 and PM emissions and the associated environmental, energy, and economic impacts. Nonfossil fuels are naturally low in sulfur content.

RDF can generally be fired to some extent in any boiler designed to fire coal but has mostly been cofired with coal in large industrial and utility boilers. One standard boiler was selected of the same capacity as most of the wood/coal cofired standard boilers, 44 MW (150 x 10^6 Btu/hr). A spreader stoker was chosen as the firing mechanism since to date it has been the preferred firing mechanism for boilers firing over 20-30 percent RDF. Some boilers are currently being designed and built to fire RDF alone. Little emission data are currently available for this type of boiler so no standard boiler was selected to represent this case. However, tests at one facility firing RDF alone achieved similar emission levels as large MSW-fired boilers with similarly designed control systems.

As discussed in Chapter 3, MSW-fired boilers are of two significantly different designs with different emission rates. Three MSW-fired boiler capacities were selected, 2.9, 44, and 117 MW (10, 150, and 400 x 10^6 Btu/hr) thermal input. The small capacity selected is typical of small modular incinerators of controlled air design with heat recovery. The two larger capacities are expected to cover the range of sizes for most new MSW-fired boilers using the mass-burn design.

Bagasse-fired boilers sold in recent years have consisted of spreader stokers and various pile burning designs. However, as discussed in Chapter 3, most new bagasse-fired boilers are expected to be spreader stokers.[2] One standard boiler capacity, 58.6 MW (200 x 10^6 Btu/hr), representing this design was selected. As shown in Figure 6-3, most boilers sold had a thermal input capacity of about this size or larger. A smaller bagasse-fired boiler was not included in the analysis because few if any smaller boilers are anticipated to be built. A larger boiler was not evaluated since economies of scale would be expected in both boiler and emission control costs.

6.1.2 Characterization of Standard Boilers

The firing mechanisms for the majority of new wood-fired boilers are similar across the capacity range as shown in Table 3-1. These units are primarily spreader or overfeed stokers with the major differences being in the type of grate selected.[3] Some other firing methods used at times to fire wood include Dutch ovens, fuel cells, and fluidized beds. However, as was discussed in Chapter 3, Dutch ovens have been phased out for new construction due to high costs, low efficiencies, and inability to follow load swings. Particulate emission rates from the other firing mechanisms are usually less than from spreader stokers. Because of the prevalence of spreader stokers as a firing mechanism for wood-fired boilers and because spreader stokers have higher uncontrolled emission rates, all of the wood-fired standard boilers were selected to be spreader stokers.

Wood/coal cofired boilers are also generally spreader stokers. For this reason and to aid in comparing the regulatory impacts among the various standard boilers, the spreader stoker was selected as the firing mechanism for these standard boilers.

RDF and coal have been fired together in both spreader stokers and in pulverized coal units. Spreader stokers have been used and are planned for boilers firing various ratios of RDF and coal from zero to 100 percent RDF. RDF use in pulverized coal units has generally been limited to around 20 percent with some tests ranging up to 30 percent RDF. Since stoker-fired boilers are the only types that have been used to fire fuel mixtures containing large percentages of RDF, the spreader stoker was selected as the firing mechanism for the standard boiler cofiring RDF and coal.

MSW-fired boilers fall into two distinct design types based on capacity. Small municipal incinerators with heat recovery are usually bought in modules, the number and size determined by the amount of waste to be burned. These modular devices often use two combustion chambers with substoichiometric air to the first chamber. This "controlled air" design was selected as representative of small MSW-fired boilers. A "mass burn" boiler which burns the waste as it is received on moving grates was selected as representative of large MSW-fired boilers.

Bagasse-fired boilers use spreader stokers, fuel cells, and horseshoes as firing methods. Horseshoes and fuel cells are pile burning designs similar to the Dutch oven used to fire wood. They differ in the shape of the furnace area but in other respects are similar in design and operation. The basic design of the bagasse-fired spreader stoker is the same as that of the wood-fired spreader stoker. Most new bagasse- fired boilers are expected to use spreader stokers so this design was selected for the bagasse-fired standard boiler.

6.1.3 Standard Boiler Specifications

The specifications for the standard boilers provide the basis for the "model boiler" environmental and economic analyses. The primary parameters specified are:

- Fuel type and quality

- Design capacity and load factor
- Flue gas characteristics

Each parameter is discussed below with an explanation of the determining factors. The design parameters for all the selected standard boilers are presented in Table 6-3. Additional design parameters required specifically for cost analysis are presented in Chapter 8.

6.1.3.1 Fuels. The fuel specifications have been chosen to represent currently available choices for nonfossil fuels and are presented in Table 6-4. The fuel characteristics, including heating value and chemical analysis, are specified to determine the combustion-related characteristics of the standard boilers.

Three wood fuels were selected. All of the standard boilers firing wood, except for one, use a wood fuel analysis representative of a hog fuel,[4] which is a mixture of wood and bark and is representative of wood fuels fired in most wood-fired boilers in the United States. The fuel moisture, sulfur, and nitrogen contents were selected as representative values based on other literature data[5] and test data presented in Appendix C. To compare the effects of firing a high ash content fuel with those of the selected fuel, a second wood composition was derived from the first and labeled "high ash bark" (HAB). The HAB composition was derived from the hog fuel composition by increasing the ash content from two percent to six percent on a dry basis, keeping the fuel moisture at 50 percent, and adjusting the other elements and fuel heating value proportionately. This high ash content is on the high end of values reported in the literature for bark.[4,6] The resulting fuel heating value is still well within the range of heating values common for wood and bark fuels.

To compare the effects of firing wood from logs that have been stored in salt water, a third wood composition was derived from the first and labeled "salt-laden wood" (SLW). The SLW composition was derived from the hog fuel composition by specifying the fuel to have 1.0 percent salt on a dry basis, keeping the fuel moisture at 50 percent, and adjusting the other elements and fuel heating value proportionately. The salt content was based

TABLE 6-3. STANDARD BOILER DESIGN SPECIFICATIONS

Model Boiler Number	1	2	3	4	5
Thermal input, MW (10^6 Btu/hr)	8.8(30)	22.0(75)	44.0(150)	117(400)	44.0(150)
Fuel[a]	Wood	Wood	Wood	Wood	HAB
Fuel rate, kg/s (ton/hr)	0.829 (3.29)	2.07 (8.22)	4.15 (16.4)	11.1 (43.9)	4.32 (17.2)
Analysis					
% sulfur	0.02	0.02	0.02	0.02	0.02
% ash	1.00	1.00	1.00	1.00	3.00
Heating value, kJ/kg (Btu/lb)	10,600 (4,560)	10,600 (4,560)	10,600 (4,560)	10,600 (4,560)	10,160 (4,370)
Excess air, %	50	50	50	50	50
Flue gas flow rate, m^3/s (acfm)	6.94(14,700)	17.3(36,700)	34.7(73,500)	92.5(196,000)	34.7(73,500)
Flue gas temperature, °K(°F)	478(400)	478(400)	478(400)	478(400)	478(400)
Load factor, %	60	60	60	60	60
Flue gas constituents,[b] kg/hr(lb/hr)					
Fly ash (before mechanical collector)[c]	66.2(146)	166(366)	332(732)	885(1950)	467(1030)
(after mechanical collector)[h]	13.3(29.3)	33.2(73.2)	66.4(146)	177(390)	93.9(207)
SO_2	—	—	—	—	—
NO_x	3.40(7.50)	8.53(18.8)	17.0(37.5)	45.3(100)	17.0(37.5)
Ash from sand classifier,[i] kg/hr(lb/hr)	29.2(64.4)	73.0(161)	146(322)	390(859)	255(563)
Bottom ash, kg/hr(lb/hr)	20.1(44.4)[j]	50.3(111)[j]	101(222)[j]	269(592)[j]	292(644)
Boiler Output, MW (10^6 Btu/hr)					
Steam	5.7(19.5)	14.3(48.7)	28.6(97.5)	76.1(260)	28.6(97.5)
Losses	3.1(10.5)	7.7(26.3)	15.4(52.5)	41.0(140)	15.4(52.5)
Efficiency, %	65	65	65	65	65
Steam quality					
Pressure,[d] kPa(psig)	1,720(250)	1,720(250)	1,720(250)	5,170(750)	1,720(250)
Temperature, °K (°F)	481(406)	481(406)	481(406)	672(750)	481(406)
Steam production,[e] kg/hr(lb/hr)	8,890(19,600)	22,200(49,000)	44,500(98,200)	101,000(223,000)	44,500(98,200)

See footnotes at end of table.

TABLE 6-3. (CONTINUED)

Model Boiler Number	6	7	8	9	10
Thermal input, MW(10^6 Btu/hr)	44.0(150)	44.0(150)	44.0(150)	117(400)	44.0(150)
Fuel[a]	SLW	75% Wood/[f,g] 25% HSE	50% Wood/[f,g] 50% HSE	50% Wood/[f,g] 50% HSE	50% Wood/[f,g] 50% LSW
Fuel rate, kg/s (ton/hr)	4.18 (16.6)	3.11/0.401 (12.3/1.59)	2.07/0.801 (8.22/3.18)	5.52/2.13 (21.9/8.47)	2.07/0.985 (8.22/3.91)
Analysis					
% sulfur	0.02	0.02/3.54	0.02/3.54	0.02/3.54	0.02/0.60
% ash	1.49	1.00/10.58	1.00/10.58	1.00/10.58	1.00/5.40
Heating value, kJ/kg (Btu/lb)	10,490 (4510)	10,600/27,440 (4,560/11,800)	10,600/27,440 (4,560/11,800)	10,600/27,440 (4,560/11,800)	10,600/22,330 (4,560/9,600)
Excess air, %	50	50	50	50	50
Flue gas flow rate, m^3/s (acfm)	34.7(73,500)	33.3(71,300)	32.4(69,200)	87.1(184,500)	33.1(70,200)
Flue gas temperature, °K(°F)	478(400)	478(400)	478(400)	478(400)	478(400)
Load factor, %	60	60	60	60	60
Flue gas constituents,[b] kg/hr(lb/hr)					
Fly ash (before mechanical collector)[c]	411(905)	348(767)	364(803)	971(2140)	290(640)
Fly ash (after mechanical collector)[h]	142(314)	69.6(153)	72.8(160)	194(428)	58(128)
SO_2	—	102(224)	197(434)	526(1160)	43.5(95.8)
NO_x	17.0(37.5)	23.5(51.7)	29.9(66.0)	79.7(176)	29.9(66.0)
Ash from sand classifier,[i] kg/hr(lb/hr)	147(325)	189(416)	231(510)	617(1360)	172(380)
Bottom ash, kg/hr(lb/hr)	101(222)	129(285)	157(348)	421(928)	117(259)
Boiler Output, MW (10^6 Btu/hr)					
Steam	28.6(97.5)	30.4(104)	32.1(110)	85.4(292)	32.1(110)
Losses	15.4(52.5)	13.6(46)	11.9(40)	31.6(108)	11.9(40)
Efficiency, %	65	69	73	73	73
Steam quality					
Pressure,[d] kPa(psig)	1,720(250)	1,720(250)	1,720(250)	5,170(750)	1,720(250)
Temperature, °K(°F)	481(406)	481(406)	481(406)	672(750)	481(406)
Steam production,[e] kg/hr(lb/hr)	44,500(98,200)	47,600(105,000)	50,300(111,000)	114,000(251,000)	50,300(111,000)

See footnotes at end of table.

TABLE 6-3. (CONTINUED)

Model Boiler Number	11	12	13	14	15
Thermal input, MW(10^6 Btu/hr)	44.0(150)	2.9(10)	44.0(150)	117(400)	58.6(200)
Fuel[a]	50% RDF/[f,g] 50% HSE	MSW	MSW	MSW	Bagasse
Fuel rate, kg/s (ton/hr)	1.63/0.801 (6.48/3.18)	0.260 (1.03)	3.88 (15.4)	10.3 (41.0)	6.43 (25.5)
Analysis					
% sulfur	0.17/3.54	0.12	0.12	0.12	Trace
% ash	19.44/10.58	22.38	22.38	22.38	1.10
Heating value, kJ/kg (Btu/lb)	13,460/27,440 (5,790/11,800)	11,340 (4,875)	11,340 (4,875)	11,340 (4,875)	9,116 (3,920)
Excess air, %	50	100	100	100	50
Flue gas flow rate, m^3/s(acfm)	31.8(67,300)	2.79(5,920)	41.8(88,500)	111(236,000)	47.7(101,000)
Flue gas temperature, °K(°F)	478(400)	478(400)	478(400)	478(400)	478(400)
Load factor, %	60	60	60	60	45
Flue gas constituents,[b] kg/hr(lb/hr)					
Fly ash (before mechanical collector)[c]	396(873)	1.36(3.00)	229(504)	608(1340)	458(1,010)
(after mechanical collector)[h]	-	-	-	-	-
SO_2	214(472)	2.23(4.92)	33.5(73.8)	89.3(197)	-
NO_x	38.6(85.0)	1.40(3.08)	21.0(46.2)	56.0(123)	18.1(40.0)
Ash from sand classifier,[i] kg/hr(lb/hr)	-	-	-	-	-
Bottom ash, kg/hr(lb/hr)	1,050(2,320)	279(615)	3,490(7,690)	9,310(20,500)	145(319)
Boiler Output, MW (10^6 Btu/hr)					
Steam	33.4(114)	1.6(5.5)	30.8(105)	81.9(280)	35.2(120)
Losses	10.6(36)	1.3(4.5)	13.2(45)	35.1(120)	23.4(80)
Efficiency, %	76	55	70	70	60
Steam quality					
Pressure,[d] kPa(psig)	3,100(450)	1,720(250)	3,100(450)	5,170(750)	1,720(250)
Temperature, °K(°F)	589(600)	481(406)	589(600)	672(750)	533(500)
Steam production,[e] kg/hr(lb/hr)	47,200(104,000)	2,510(5,540)	43,600(96,000)	109,000(241,000)	51,700(114,000)

See footnotes at end of table.

FOOTNOTES TO TABLE 6-3:

[a]Wood - hog fuel (wood/bark mixture)
HAB - high ash bark
SLW - salt-laden wood
HSE - high sulfur eastern coal
LSW - low sulfur western coal
RDF - refuse derived fuel
MSW - municipal solid waste

[b]Uncontrolled emissions.

[c]Fly ash before mechanical collector means uncontrolled emissions prior to any control device whether a mechanical collector is used or not.

[d]Guage pressure.

[e]Assuming a saturated condensate return at 10 psig.

[f]Average fuel mixture on heat input basis.

[g]Boilers cofiring wood and coal are designed to fire wood up to 100 percent of the boiler capacity. These boilers and their emission control systems are designed to fire coal only up to 30 percent or 60 percent of the boiler capacity depending on whether the average cofiring ratio is 25 percent or 50 percent. The model boiler cofiring RDF and coal is designed to fire coal up to 100 percent of capacity and RDF up to 60 percent of capacity.

[h]Fly ash after the mechanical collector is shown only for cases where fly ash reinjection is used. The value shown represents a mechanical collector used as a precleaner prior to another control device. For model boilers 1a - 4a, where the mechanical collector is the final control device, this value would be the mass equivalent of an emission level of 258 ng/J (0.6 lb/10^6 Btu).

[i]Sand classifiers are only used with systems employing fly ash reinjection (model boilers 1-10). The value shown represents the difference in the amount of fly ash collected by the mechanical collector and the amount of fly ash reinjected into the boiler furnace.

[j]These values are for cases where the mechanical collector is used as a precleaner prior to another control device. Where the mechanical collector is the final control device, these values would be 34.3, 85.7, 171, and 458 kg/hr (75.7, 189, 378, and 1009 lb/hr) for model boilers 1a, 2a, 3a, and 4a respectively.

TABLE 6-4. ULTIMATE ANALYSES OF THE FUELS SELECTED FOR THE STANDARD BOILERS

Fuel[a]	Composition, % by weight							Gross Heating Value kJ/kg (Btu/lb)
	Moisture	Carbon	Hydrogen	Nitrogen	Oxygen	Sulfur	Ash	
Wood	50.00	26.95	2.85	0.08	19.10	0.02	1.00	10,600 (4,560)
HAB	50.00	25.85	2.73	0.08	18.32	0.02	3.00	10,160 (4,370)
SLW	50.00	26.68	2.82	0.08	18.91	0.02	1.49[b]	10,490 (4,510)
RDF[c]	22.42	31.30	4.62	0.61	21.44	0.17	19.44	13,460 (5,790)
MSW[c]	27.14	26.73	3.60	0.17	19.74	0.12	22.38	11,340 (4,875)
Bagasse	52.00	22.60	3.10	0.10	21.10	Trace	1.10	9,116 (3,920)
HSE	8.79	64.80	4.43	1.30	6.56	3.54	10.58	27,440 (11,800)
LSW	20.80	57.60	3.20	1.20	11.20	0.60	5.40	22,330 (9,600)

[a]Wood - hog fuel (wood/bark mixture)
HAB - high ash bark
SLW - salt-laden wood
RDF - refuse derived fuel
MSW - municipal solid waste
HSE - high sulfur eastern coal
LSW - low sulfur western coal

[b]Salt makes up 0.5 percent of the fuel composition and is included here as ash.

[c]Composition does not total 100 percent due to the presence of chlorine which is not shown here.

on fuel analysis data for salt-laden wood[7,8] and the heating value is still well within the range of values common for wood and bark fuels.

The RDF composition was obtained by averaging RDF analyses from several facilities that have fired RDF.[9] The MSW composition was taken from a performance test conducted on boilers at an operating facility.[10] The analysis compares closely with reported "typical" compositions for MSW[11] except that the heating value of the selected waste is somewhat higher. However, the heating value of MSW in the United States has been increasing with time, and the heating value of the selected waste falls well within the range of values predicted by several studies for the 1985 - 1990 time frame.[12]

The bagasse composition was based on an average dry composition reported in the Cane Sugar Handbook.[13] Sulfur and nitrogen concentrations were based on values reported in various other sources. Fuel moisture was set at an intermediate level based on values reported in the Gilmore Sugar Manual.[14]

Two coal compositions were selected for the cofiring cases. All of the cofired standard boilers except one fire a coal representative of an eastern high sulfur, high ash coal. To consider a contrasting coal composition, one standard boiler was also selected to fire a coal representative of a western low sulfur, low ash coal. Analyses for these coals are identical to those used in the industrial boiler study.[15]

6.1.3.2 Boiler Capacities and Load Factors. The capacities of the standard boilers selected in Section 6.1 are based on the maximum heat input to the boiler. The heat input together with the heating value of the fuel determines the fuel firing rate. Capacities of boilers, however, are often stated on a steam output basis. To quantify the steam output, the thermal efficiency and steam quality of the boiler must be specified. The thermal efficiency of the boiler is the measure of the percentage of heat input which is transferred to the steam cycle and is a function of the fuel properties, firing method, flue gas characteristics, and boiler heat losses. Thermal efficiencies shown in Table 6-3 are generally based on values reported in the literature for wood,[5] MSW,[16,17] and bagasse-fired[18] boilers.

Thermal efficiencies shown for the combination fuel boilers are adjusted to reflect the proportion of coal fired based on values used in the industrial boiler study[19] for coal-fired boilers.

The quality of the steam is specified in terms of temperature and pressure. The steam quality varies with the intended steam use. The steam temperatures and pressures specified for the standard boilers are those commonly found in various applications for the selected boiler capacities. Steam qualities were selected based on watertube boiler sales data[20] for wood and bagasse-fired boilers, steam qualities selected for coal-fired boilers in the industrial boiler study,[19] and various literature references.[21,22]

The capacities of the standard boilers represent maximum firing rates. Boilers, however, seldom operate at maximum capacity year-round. To analyze impacts on an annual operating basis, an appropriate measure of actual boiler usage must be selected. The load factor (or capacity utilization factor) is the actual annual fuel consumption as a percentage of the potential annual fuel consumption at maximum firing rate. Load factors for industrial boilers are estimated to range from 30 to 80 percent.[23] Since nonfossil fuel fired boilers provide steam for similar end uses in industry as fossil fuel fired boilers, this range was assumed to be representative. Load factors for MSW resource recovery plants installed by 1990 are forecasted to average 60-80 percent.[24]

Low load factors generally represent "nonprocess" boilers or boilers used in seasonal industries, such as bagasse-fired boilers. High load factors generally represent process or utility boilers whose output is tied directly to plant production. Load factors can vary considerably from plant to plant and from industry to industry and are influenced by such items as the economic climate of the country, the availability of nonfossil fuels, the reliability of the boiler and fuel feeding equipment, and decisions to buy oversized boilers to allow for plant expansions. Load factors for the standard boilers were generally set at 60 percent for each boiler and fuel combination. Bagasse-fired boilers were assigned a lower load factor of 45 percent due to the seasonal nature of the industry. Some different load factors are used in the economic analyses for specific boiler applications appearing in Chapter 9.

6.1.3.3 Flue Gas Characteristics. Temperature, composition, and volumetric flow rate are the main flue gas characteristics upon which the design of emission control systems are based. These characteristics are mainly affected by fuel composition and boiler excess air. Fuel analyses are presented in Table 6-4. A representative excess air value was selected for each standard boiler and is included in Table 6-3. The pollutant concentrations in the flue gas are calculated based on the excess air rate, the chemical composition of the fuel, and the pollutant emission factors developed in Chapter 3 for each standard boiler.[25]

6.2 SELECTION OF CONTROL ALTERNATIVES

The environmental, energy, and economic impacts of applying various control levels to the standard boilers are presented in Chapters 7 and 8. In order to perform those analyses, various emission control levels and control technologies are identified. This section presents the rationale for the selection of both the emission control levels and control techniques.

A baseline or reference control level provides a basis for evaluating the incremental impacts of more stringent control levels. In addition, two more stringent control levels are also specified in order to evaluate their impacts. These control levels were generally selected based on the range of emission test data presented in Chapter 4. The selections of the model boiler control techniques used to meet each emission level are also based on data presented in Chapter 4.

The major pollutant of concern from nonfossil fuel fired boilers is particulate matter (PM). PM is the only pollutant for which controls are currently being required for NFFBs under existing standards. No NO_x controls are considered since control techniques for NO_x reduction have typically not been applied to NFFBs. When coal or oil is fired together with a nonfossil fuel, emissions of SO_2 are generally increased compared to 100 percent nonfossil fuel firing. Therefore, several cofired standard boilers were selected for analysis to show the impacts of SO_2 control requirements on cofired boilers.

6.2.1 Baseline Control Alternative

The baseline control alternative generally represents the highest level of emissions expected under the current mix of existing regulations (SIPs and 40 CFR 60 Subparts D and E). The control method selected to meet the baseline alternative generally represents the least effective control method applicable to a particular pollutant and standard boiler. In most cases, this also represents the least expensive control method.

The control levels and control methods selected as the baseline control alternatives for each fuel type are shown in Table 6-5. For most of the fuel types the baseline emission level was chosen as the average of existing State and Federal emission regulations. These regulations are presented in Section 3.3.

For wood-fired boilers the emission level chosen was 258 ng/J (0.6 lb/10^6Btu) rather than the average of existing regulations. Existing State particulate matter emissions for wood-fired boilers vary widely, as shown in Table 3-19 in Chapter 3. Setting the baseline for wood-fired boilers at the average SIP level would have excluded mechanical collectors as a control method in the model boiler analysis. However, mechanical collectors are still used in many states for particulate matter control. Therefore, the baseline control alternative was set so that this technology could be included in the model boiler analysis.

6.2.2 Emission Control Level I

Emission Control Level I represents a control level moderately more effective than the baseline level. The emission levels and control technologies selected for Control Level I are presented in Table 6-5.

The emission levels and control methods chosen for Control Level I for PM are generally based on the "average" emissions shown in Chapter 4 for each boiler and fuel type. If insufficient data were available to determine the "average" case, the emission level and control method selected are the average emission level and control method for a similar fuel and boiler combination for which data are available.

TABLE 6-5. EMISSION CONTROL LEVELS AND APPLICABLE CONTROL METHODS

Fuel Type[a]	Baseline Control Level: Control Techniques[b]	Baseline Control Level: Emission Level[c] ng/J(lb/10^6Btu)	Control Level I: Control Techniques[b]	Control Level I: Emission Level ng/J(lb/10^6Btu)	Control Level II: Control Techniques[b]	Control Level II: Emission Level ng/J(lb/10^6Btu)
PM Emissions						
Wood	MC	258 (0.60)	WS	64.5 (0.15)	WS,FF ESP,EGB	21.5 (0.05)
HAB,SLW	WS	146 (0.34)	WS	64.5 (0.15)	FF	21.5 (0.05)
Wood/Coal	WS	43.0 - 138 (0.10 - 0.32)	WS	43.0 - 64.5 (0.10 - 0.15)	FF,ESP	21.5 (0.05)
RDF/Coal	WS	138 (0.32)	WS	64.5 (0.15)	FF,ESP	21.5 (0.05)
MSW[d]	ESP	73.1 (0.17)	ESP	43.0 (0.10)	ESP	21.5 (0.05)
MSW[e]	None	129 (0.30)	WS	64.5 (0.15)	FF	21.5 (0.05)
Bagasse	MC	267 (0.62)	WS	86.0 (0.2)	-	-
SO_2 Emissions						
Wood/Coal RDF/Coal	FGD-WS	526 - 1075 (1.2 - 2.5)	FGD-WS FGD-DS	70 percent Control	FGD-WS	90 percent Control

[a]Wood - hog fuel (wood/bark mixture)
HAB - high ash bark
SLW - salt-laden wood
Coal - includes high and low sulfur coals
RDF - refuse derived fuel
MSW - municipal solid waste

[b]WS - wet scrubber
FF - fabric filter
ESP - electrostatic precipitator
EGB - electrostatic gravel bed filter
MC - mechanical collector
FGD-DS - flue gas desulfurization (dry scrubbing)
FGD-WS - flue gas desulfurization (wet scrubbing)

[c]Emission ranges reflect different baseline emission levels for different sizes of standard boilers.

[d]Includes all MSW-fired boilers except small modular units.

[e]Includes only small modular MSW-fired boilers.

6.2.3 Emission Control Level II

Emission Control Level II is based on the more stringent emission levels shown achievable by the emission data in Chapter 4. The emission limits and control techniques selected are presented in Table 6-5. Where data are available the selection of control methods to meet Control Level II are based on the controls used on existing NFFBs to meet more stringent emission levels. If there is insufficient data to determine a control method on this basis, the control method is based on control devices which can meet stringent emission levels for other fuel categories.

Control Level II was not evaluated for bagasse-fired boilers because data are not available for high efficiency controls for this fuel.

6.3 MODEL BOILERS

Model boilers are combinations of standard boilers and emission control systems which are selected to allow evaluation of cost, environmental, and energy impacts of air pollution control across a range of boiler types and sizes for several emission control levels. Results of these evaluations are presented in Chapters 7 and 8.

The model boiler selection process is intended to generate a set of model boilers which represents the expected population of new NFFBs and emission control systems utilizing Baseline, Level I, and Level II controls. Control systems selected to achieve compliance with each control level are discussed in Section 6.2. In many cases more than one emission control system or combination of control systems can achieve a specified control level, and consequently, several alternatives were evaluated to examine their relative impacts.

There is, however, a practical limit to the number of model boilers that can be examined. As a guideline, model boilers were generally selected to represent what appeared to be a demonstrated and lowest cost method or combination of methods to achieve the required control levels for each boiler/fuel/control level combination considering technology limits and development status.

Control techniques selected for model boiler evaluations include mechanical collectors, wet scrubbers, electrostatic precipitators, fabric filters, and electrostatic gravel bed filters for particulate control. Double alkali and lime wet scrubbing and lime dry scrubbing flue gas desulfurization systems were selected as SO_2 control techniques. Model boilers that include these control techniques are presented in Table 6-6. These model boilers will serve as the basis for the cost, environmental, and energy impact analyses.

6.4 EMISSION LEVELS

For the purpose of evaluating environmental impacts, numerical emission levels for each pollutant have been set for each standard boiler (uncontrolled, Baseline, Control Level I, and Control Level II). These numerical emission levels for the standard boilers are shown in Table 6-7 for the different fuel types and boiler capacities.

It should be noted that many issues such as economic and environmental impacts are not considered in the selection of Control Levels I and II. The purpose of these numerical levels is to evaluate the impacts of various control techniques and emission levels on the model boilers. They do not necessarily represent final numbers which will be selected as the standard.

TABLE 6-6. MODEL BOILERS

Model Boiler Number	Boiler Capacity (thermal input)	Fuel[a]	Control Level[b]		Emission Control System[c]	
			PM	SO_2	PM	SO_2
1a	8.8 MW	Wood	B	B	MC	-
1b	(30×10^6 Btu/hr)		I	B	MC,WS	-
1c			II	B	MC,WS	-
1d			II	B	MW,FF	-
1e			II	B	MC,ESP	-
2a	22.0 MW	Wood	B	B	MC	-
2b	(75×10^6 Btu/hr)		I	B	MC,WS	-
2c			II	B	MC,WS	-
2d			II	B	MC,FF	-
2e			II	B	MC,ESP	-
2f			II	B	MC,EGB	-
3a	44.0 MW	Wood	B	B	MC	-
3b	(150×10^6 Btu/hr)		I	B	MC,WS	-
3c			II	B	MC,WS	-
3d			II	B	MC,FF	-
3e			II	B	MC,ESP	-
3f			II	B	MC,EGB	-
4a	117 MW	Wood	B	B	MC	-
4b	(400×10^6 Btu/hr)		I	B	MC,WS	-
4c			II	B	MC,WS	-
4d			II	B	MC,FF	-
4e			II	B	MC,ESP	-
4f			II	B	MC,EGB	-
5a	44.0 MW	HAB	B	B	MC,WS	-
5b	(150×10^6 Btu/hr)		I	B	MC,WS	-
5c			II	B	MC,FF	-
6a	44.0 MW	SLW	B	B	MC,WS	-
6b	(150×10^6 Btu/hr)		I	B	MC,WS	-
6c			II	B	MC,FF	-
7a	44.0 MW	75% Wood/[d]	B	B	MC,WS	-
7b	(150×10^6 Btu/hr)	25% HSE	I	B	MC,WS	-
7c			I	I	MC,FGD-WS	FGD-WS
7d			II	B	MC,ESP	-
7e			II	B	MC,FF	-
7f			II	I	MC,FF	FGD-DS
7g			II	II	MC,ESP	FGD-WS
8a	44.0 MW	50% Wood/[d]	B	B	MC,FGD-WS	FGD-WS
8b	(150×10^6 Btu/hr)	50% HSE	I	B	MC,FGD-WS	FGD-WS
8c			I	I	MC,FGD-WS	FGD-WS
8d			I	II	MC,FGD-WS	FGD-WS
8e			II	B	MC,FF	FGD-DS[e]
8f			II	I	MC,FF	FGD-DS
8g			II	II	MC,ESP	FGD-WS

See footnotes at end of table.

TABLE 6-6. (CONTINUED)

Model Boiler Number	Boiler Capacity (thermal input)	Fuel[a]	Control Level[b] PM	Control Level[b] SO_2	Emission Control System[c] PM	Emission Control System[c] SO_2
9a	117 MW	50% Wood/[d]	B	B	MC,FGD-WS	FGD-WS
9b	(400×10^6 Btu/hr)	50% HSE	I	I	MC,FGD-WS	FGD-WS
9c			II	I	MC,FF	FGD-DS
9d			II	II	MC,ESP	FGD-WS
10a	44.0 MW	50% Wood/[d]	B	B	MC,WS	-
10b	(150×10^6 Btu/hr)	50% LSW	I	B	MC,WS	-
10c			I	I	MC,FGD-WS	FGD-WS
10d			I	II	MC,FGD-WS	FGD-WS
10e			II	B	MC,FF	-
10f			II	B	MC,ESP	-
10g			II	I	MC,FF	FGD-DS
10h			II	II	MC,ESP	FGD-WS
11a	44.0 MW	50% RDF/[d]	B	B	FGD-WS	FGD-WS
11b	(150×10^6 Btu/hr)	50% HSE	I	I	FGD-WS	FGD-WS
11c			I	II	FGD-WS	FGD-WS
11d			II	I	ESP	FGD-WS
11e			II	II	ESP	FGD-WS
12a	2.9 MW	MSW	B	B	-	-
12b	(10×10^6 Btu/hr)		I	B	WS	-
12c			II	B	FF	-
13a	44.0 MW	MSW	B	B	ESP	-
13b	(150×10^6 Btu/hr)		I	B	ESP	-
13c			II	B	ESP	-
14a	117 MW	MSW	B	B	ESP	-
14b	(400×10^6 Btu/hr)		I	B	ESP	-
14c			II	B	ESP	-
15a	58.6 MW	Bagasse	B	B	MC	-
15b	(200×10^6 Btu/hr)		I	B	WS	-

[a]Wood - hog fuel (wood/bark mixture)
HAB - high ash bark
SLW - salt-laden wood
HSE - high sulfur eastern coal
LSW - low sulfur western coal
RDF - refuse derived fuel
MSW - municipal solid waste

[b]B refers to Baseline control level.
I refers to Control Level I.
II refers to Control Level II.

[c]MC - mechanical collector
WS - wet scrubber
FF - fabric filter
ESP - electrostatic precipitator
EGB - electrostatic gravel bed filter
FGD-WS - flue gas desulfurization; double alkali or lime wet scrubber
FGD-DS - flue gas desulfurization; lime dry scrubber
Control systems separated by a comma mean that both are used at the same time, not that either may be used independently. Mechanical collectors are included for fly ash reinjection on all of the boilers firing wood.

[d]Average fuel mixture on a heat input basis.

[e]Only a portion of the flue gas is scrubbed.

TABLE 6-7. EMISSION LEVELS FOR THE MODEL BOILERS

Model Boiler Number	Fuel[a]	Standard Boiler MW (10^6Btu/hr)	Uncontrolled Emissions ng/J (lb/10^6 Btu) PM-BMC[c]	PM-AMC[c]	SO_2[g]	Baseline Control Level[d] ng/J (lb/10^6 Btu) PM	SO_2	Control Level I ng/J (lb/10^6 Btu) PM	SO_2[e]	Control Level II ng/J (lb/10^6 Btu) PM	SO_2[f]
1	Wood	8.8 (30)	2100 (4.88)	418 (0.973)	- -	258 (0.6)	- -	64.5 (0.15)	- -	21.5 (0.05)	- -
2	Wood	22.0 (75)	2100 (4.88)	418 (0.973)		258 (0.6)		64.5 (0.15)		21.5 (0.05)	
3	Wood	44.0[i] (150)	2100 (4.88)	418 (0.973)	-	258 (0.6)	-	64.5 (0.15)	- -	21.5 (0.05)	- -
4	Wood	117 (400)	2100 (4.88)	418 (0.973)	- -	258 (0.6)	-	64.5 (0.15)	- -	21.5 (0.05)	- -
5	HAB	44.0 (150)	2950 (6.87)	593 (1.38)	- -	146 (0.34)	- -	64.5 (0.15)	-	21.5 (0.05)	- -
6	SLW	44.0 (150)	2590 (6.03)	899 (2.09)	- -	146 (0.34)	- -	64.5 (0.15)	-	21.5 (0.05)	- -
7	75% Wood/[b] 25% HSE	44.0 (150)	2200 (5.11)	440 (1.02)	641 (1.49)	138 (0.32)	641 (1.49)	64.5 (0.15)	194 (0.45)	21.5 (0.05)	64.5 (0.15)
8	50% Wood/[b] 50% HSE	44.0 (150)	2300 (5.35)	460 (1.07)	1240 (2.89)	138 (0.32)	1075 (2.50)	64.5 (0.15)	374 (0.87)	21.5 (0.05)	125 (0.29)
9	50% Wood/[b] 50% HSE	117 (400)	2300 (5.35)	460 (1.07)	1240 (2.89)	43.0 (0.10)	516 (1.2)	43.0 (0.10)	374 (0.87)	21.5 (0.05)	125 (0.29)
10	50% Wood/[b] 50% LSW	44.0 (150)	1840 (4.27)	367 (0.853)	275 (0.639)	138 (0.32)	275 (0.639)	64.5 (0.15)	81.7 (0.19)	21.5 (0.05)	27.5 (0.06)
11	50% RDF/[b] 50% HSE	44.0 (150)	2500 (5.82)	- -	1350 (3.15)	138 (0.32)	1075 (2.50)	64.5 (0.15)	405 (0.94)	21.5 (0.05)	135 (0.31)
12	MSW	2.9 (10)	129 (0.30)	- -	212 (0.49)	129 (0.30)	212 (0.49)	64.5 (0.15)	212 (0.49)	21.5 (0.05)	212 (0.49)
13	MSW	44.0[i] (150)	1440 (3.36)	- -	212 (0.49)	73.1 (0.17)	212 (0.49)	43.0 (0.10)	212 (0.49)	21.5 (0.05)	212 (0.49)
14	MSW	117 (400)	1440 (3.36)	- -	212 (0.49)	73.1 (0.17)	212 (0.49)	43.0 (0.10)	212 (0.49)	21.5 (0.05)	212 (0.49)
15	Bagasse	58.6 (200)	2170 (5.05)	- -	- -	267 (0.62)	- -	86.0 (0.20)	- -	-[h] -	- -

See footnotes on second page.

FOOTNOTES TO TABLE 6-7.

[a]Wood - hog fuel (wood/bark mixture)
HAB - high ash bark
SLW - salt-laden wood
RDF - refuse derived fuel
MSW - municipal solid waste
HSE - high sulfur eastern coal
LSW - low sulfur western coal

[b]Average fuel mixture on a heat input basis.

[c]BMC - before mechanical collector or any other control equipment.
AMC - after mechanical collector when the mechanical collector is not the final control device.
Both values are included only for cases with fly ash reinjection.

[d]Emission level equivalent to the uncontrolled emission rate, or to the highest emission rate expected under the current mix of State and Federal Regulations. For model boilers 1-4 the level also represents emissions after the mechnical collector when the mechanical collector is the final control device.

[e]The emission level shown represents a 70 percent reduction from uncontrolled SO_2 emissions for the combination fuel boilers and no control for the others.

[f]The emission level shown represents a 90 percent reduction from uncontrolled SO_2 emissions for the combination fuel boilers and no control for the others.

[g]SO_2 emissions for boilers firing bagasse of 100 percent wood are low and have not been quantified for this analysis.

[h]A level more stringent than Control Level I was not evaluated.

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7. ENVIRONMENTAL AND ENERGY IMPACTS

An analysis of the environmental and energy impacts that result from applying various emission control technologies to nonfossil fuel fired boilers (NFFBs) is presented in this chapter. This environmental and energy impact analysis is based on an evaluation of the model boilers presented in Chapter 6. The focus of the model boiler impact analysis is to determine the incremental increase or decrease over the baseline control level, of air pollution, water pollution, solid waste, and energy impacts for two alternative control levels. The baseline control level corresponds to no change in existing regulations and represents the controls required under current State and NSPS regulations (40 CFR 60 Subparts D and E) as discussed in Chapter 6. The national impacts of applying these control levels to new NFFBs were evaluated based on projections of boiler population growth and are presented in this chapter. Table 7-1 lists the emission limits for the baseline and alternative control levels which serve as the basis for the analysis of environmental and energy impacts. The technologies that can be used to meet these limits are specified in Chapter 6 and described in Chapter 4.

7.1 AIR POLLUTION IMPACTS

Emissions from NFFBs include particulate matter (PM) and sulfur dioxide (SO_2). Particulate matter is the predominant air pollutant from boilers fired with 100 percent nonfossil fuel. Emissions of SO_2 are emitted in much smaller quantities than particulates due to the low sulfur content of nonfossil fuels. For this reason, the impacts of controlling SO_2 emissions from boilers firing 100 percent nonfossil fuel are not considered. However, SO_2 emissions are of concern from combination fuel boilers cofiring fossil and nonfossil fuels. The following analysis deals with PM emissions for boilers fired with 100 percent nonfossil fuel and with PM and SO_2 emissions for boilers cofiring fossil and nonfossil fuels.

TABLE 7-1. EMISSION LEVELS FOR MODEL BOILERS

Model Boiler Number	Fuel[a]	Standard Boiler MW (10^6 Btu/hr)	Uncontrolled Emissions ng/J (lb/10^6 Btu) PM-BMC[c]	PM-AMC[c]	SO_2[g]	Baseline Control Level[d] ng/J (lb/10^6 Btu) PM	SO_2	Control Level I ng/J (lb/10^6 Btu) PM	SO_2[e]	Control Level II ng/J (lb/10^6 Btu) PM	SO_2[f]
1	Wood	8.8 (30)	2100 (4.88)	418 (0.973)	-	258 (0.6)	- -	64.5 (0.15)	- -	21.5 (0.05)	- -
2	Wood	22.0 (75)	2100 (4.88)	418 (0.973)		258 (0.6)	-	64.5 (0.15)	-	21.5 (0.05)	- -
3	Wood	44.0[i] (150)	2100 (4.88)	418 (0.973)	-	258 (0.6)	- -	64.5 (0.15)	- -	21.5 (0.05)	- -
4	Wood	117 (400)	2100 (4.88)	418 (0.973)	-	258 (0.6)	-	64.5 (0.15)	- -	21.5 (0.05)	- -
5	HAB	44.0 (150)	2950 (6.87)	593 (1.38)	- -	146 (0.34)	- -	64.5 (0.15)	- -	21.5 (0.05)	- -
6	SLW	44.0 (150)	2590 (6.03)	899 (2.09)	- -	146 (0.34)	- -	64.5 (0.15)	-	21.5 (0.05)	- -
7	75% Wood/[b] 25% HSE	44.0 (150)	2200 (5.11)	440 (1.02)	641 (1.49)	138 (0.32)	641 (1.49)	64.5 (0.15)	194 (0.45)	21.5 (0.05)	64.5 (0.15)
8	50% Wood/[b] 50% HSE	44.0 (150)	2300 (5.35)	460 (1.07)	1240 (2.89)	138 (0.32)	1075 (2.50)	64.5 (0.15)	374 (0.87)	21.5 (0.05)	125 (0.29)
9	50% Wood/[b] 50% HSE	117 (400)	2300 (5.35)	460 (1.07)	1240 (2.89)	43.0 (0.10)	516 (1.2)	43.0 (0.10)	374 (0.87)	21.5 (0.05)	125 (0.29)
10	50% Wood/[b] 50% LSW	44.0 (150)	1840 (4.27)	367 (0.853)	275 (0.639)	138 (0.32)	275 (0.639)	64.5 (0.15)	81.7 (0.19)	21.5 (0.05)	27.5 (0.06)
11	50% RDF/[b] 50% HSE	44.0 (150)	2500 (5.82)	-	1350 (3.15)	138 (0.32)	1075 (2.50)	64.5 (0.15)	405 (0.94)	21.5 (0.05)	135 (0.31)
12	MSW	2.9 (10)	129 (0.30)	- -	212 (0.49)	129 (0.30)	212 (0.49)	64.5 (0.15)	212 (0.49)	21.5 (0.05)	212 (0.49)
13	MSW	44.0[i] (150)	1440 (3.36)	- -	212 (0.49)	73.1 (0.17)	212 (0.49)	43.0 (0.10)	212 (0.49)	21.5 (0.05)	212 (0.49)
14	MSW	117 (400)	1440 (3.36)	- -	212 (0.49)	73.1 (0.17)	212 (0.49)	43.0 (0.10)	212 (0.49)	21.5 (0.05)	212 (0.49)
15	Bagasse	58.6 (200)	2170 (5.05)	- -	- -	267 (0.62)	- -	86.0 (0.20)	- -	-[h] -	- -

See footnotes on second page.

FOOTNOTES TO TABLE 7-1.

[a]Wood - hog fuel (wood/bark mixture)
HAB - high ash bark
SLW - salt-laden wood
RDF - refuse derived fuel
MSW - municipal solid waste
HSE - high sulfur eastern coal
LSW - low sulfur western coal

[b]Average fuel mixture on a heat input basis.

[c]BMC - before mechanical collector or any other control equipment.
AMC - after mechanical collector when the mechanical collector is not the final control device.
Both values are included only for cases with fly ash reinjection.

[d]Emission level equivalent to the uncontrolled emission rate, or to the highest emission rate expected under the current mix of State and Federal Regulations. For model boilers 1-4 the level also represents emissions after the mechnical collector when the mechanical collector is the final control device.

[e]The emission level shown represents a 70 percent reduction from uncontrolled SO_2 emissions for the combination fuel boilers and no control for the others.

[f]The emission level shown represents a 90 percent reduction from uncontrolled SO_2 emissions for the combination fuel boilers and no control for the others.

[g]SO_2 emissions for boilers firing bagasse of 100 percent wood are low and have not been quantified for this analysis.

[h]A level more stringent than Control Level I was not evaluated.

7.1.1 Primary Air Impacts

7.1.1.1 Model boiler emissions. The annual model boiler emissions for PM and SO_2 are presented in Table 7-2. This table presents annual emissions in megagrams per year (Mg/yr) and tons per year (tons/yr) for uncontrolled boilers along with emissions for boilers controlled to the Baseline Level and Control Levels I and II. The table illustrates the relative emission levels that can be achieved by applying more efficient controls.

The emission reduction impacts of the various control levels are better shown in Tables 7-3 and 7-4 for each of the model boilers. Table 7-3 shows the annual emission reductions of PM and SO_2 for the Baseline Control Level and Control Levels I and II over the uncontrolled emission level. Table 7-4 shows the incremental annual emission reductions of Control Levels I and II over the Baseline Control Level. The reductions shown in Table 7-4 are presented graphically in Figures 7-1 and 7-2.

As shown in Table 7-3 baseline controls have a large impact on annual PM emissions from most of the model boilers. The amount of emission reductions for the range of model boiler sizes and fuel types generally varies from 87.7 to 95.0 percent for the baseline case. The 2.9 MW MSW-fired boiler does not fall in this range because uncontrolled emissions for this boiler are below the current mix of regulations which apply to these boilers. The Baseline Control Level for the 117 MW 50% Wood/50% HSE fired boiler requires a 98.1 percent reduction in uncontrolled PM emissions. The baseline emissions for this boiler are significantly lower than for the other model boilers. This is because fossil fuel and wood residue fired boilers, which are capable of firing fossil fuel at a heat input rate greater than 250 million Btu/hr, are already subject to standards of performance, Fossil-Fuel Fired Steam Generators (40 CFR 60 Subpart D).

The Baseline Control Level does not have as large an impact on SO_2 emissions for the model boilers. The range of emission reductions varies from 0 to 58.5 percent for the cofired model boilers. The 117 MW 50 percent Wood/50 percent HSE fired boiler has a lower baseline emission level than the other model boilers thus requiring a higher percent reduction in uncontrolled SO_2 emissions.

TABLE 7-2. ANNUAL MODEL BOILER PM AND SO_2 EMISSIONS[a]

Model Boiler Number	Boiler Capacity[b] MW (10^6Btu/hr)	Fuel[c]	Uncontrolled Mg/yr(tons/yr) PM[d]	SO_2[f]	Baseline Mg/yr(tons/yr) PM	SO_2	Control Level I Mg/yr(tons/yr) PM	SO_2	Control Level II Mg/yr(tons/yr) PM	SO_2
1	8.8 (30)	Wood	349 (385)	- -	42.9 (47.3)	- -	10.7 (11.8)	- -	3.57 (3.94)	- -
2	22.0 (75)	Wood	873 (962)	- -	107 (118)	- -	26.9 (29.6)	- -	8.94 (9.86)	- -
3	44.0 (150)	Wood	1745 (1924)	- -	215 (237)	- -	53.6 (59.1)	-	17.9 (19.7)	- -
4	117 (400)	Wood	4654 (5130)	- -	572 (631)	- -	143 (158)	- -	47.7 (52.6)	- -
5	44.0 (150)	HAB	2457 (2708)	-	122 (134)	-	53.6 (59.1)	- -	17.9 (19.7)	- -
6	44.0 (150)	SLW	2156 (2377)	-	122 (134)	- -	53.6 (59.1)	- -	17.9 (19.7)	- -
7	44.0 (150)	75% wood/[e] 25% HSE	1827 (2014)	533 (587)	114 (126)	533 (587)	53.6 (59.1)	160 (176)	17.9 (19.7)	53.3 (58.7)
8	44.0 (150)	50% wood/[e] 50% HSE	1913 (2109)	1033 (1139)	114 (126)	894 (986)	53.6 (59.1)	310 (342)	17.9 (19.7)	103 (114)
9	117 (400)	50% wood/[e] 50% HSE	5102 (5624)	2756 (3038)	95.3 (105)	1144 (1261)	95.3 (105)	826 (911)	47.7 (52.6)	276 (304)
10	44.0 (150)	50% wood/[e] 50% LSW	1527 (1683)	229 (252)	114 (126)	229 (252)	53.6 (59.1)	68.6 (75.6)	17.9 (19.7)	22.9 (25.2)
11	44.0 (150)	50% RDF/[e] 50% HSE	2081 (2294)	1127 (1242)	114 (126)	894 (986)	53.6 (59.1)	338 (373)	17.9 (19.7)	113 (124)
12	2.9 (10)	MSW	7.15 (7.88)	11.7 (12.9)	7.15 (7.88)	11.7 (12.9)	3.57 (3.94)	11.7 (12.9)	1.19 (1.31)	11.7 (12.9)
13	44.0 (150)	MSW	1202 (1325)	175 (193)	60.8 (67.0)	175 (193)	35.7 (39.4)	175 (193)	17.9 (19.7)	175 (193)
14	117 (400)	MSW	3204 (3532)	467 (515)	162 (179)	467 (515)	95.3 (105)	467 (515)	47.7 (52.6)	467 (515)
15	58.6 (200)	Bagasse	1806 (1991)	- -	221 (244)	- -	71.5 (78.8)	- -	-[g] -	- -

[a]The capacity factor for bagasse-fired boilers is 0.45 and for all other boilers is 0.60.

[b]Based on thermal input

[c]Wood - hog fuel (wood/bark mixture)
HAB - high ash bark
SLW - salt-laden wood
RDF - refuse derived fuel
MSW - municipal solid waste
HSE - high sulfur eastern coal
LSW - low sulfur western coal

[d]For boilers with flyash reinjection this value is for emissions prior to the multicyclone.

[e]Average fuel mixture on a heat input basis.

[f]SO_2 emissions for boilers firing bagasse or 100 percent wood are low and have not been quantified for this analysis.

[g]Control level II was not evaluated for bagasse-fired boilers.

TABLE 7-3. ANNUAL EMISSION REDUCTIONS ACHIEVED BY BASELINE AND CONTROL LEVELS I AND II OVER UNCONTROLLED EMISSION LEVELS

		Baseline Control Level				Control Level I				Control Level II			
		PM		SO_2		PM		SO_2		PM		SO_2	
Capacity[a] MW(10^6Btu/hr)	Fuel[b]	Mg/yr Reduction	Percent Reduction	Mg/yr Reduction	Percent Reduction	Mg/yr Reduction	Percent Reduction	Mg/yr Reduction	Percent Reduction	Mg/yr Reduction	Percent Reduction	Mg/yr Reduction	Percent Reduction
8.8 (30)	Wood	306	87.7	0	0	338	96.9	0	0	345	99.0	0	0
22.0 (75)	Wood	766	87.7	0	0	846	96.9	0	0	864	99.0	0	0
44.0 (150)	Wood	1530	87.7	0	0	1691	96.9	0	0	1727	99.0	0	0
117 (400)	Wood	4082	87.7	0	0	4511	96.9	0	0	4606	99.0	0	0
44.0 (150)	HAB	2335	95.0	0	0	2403	97.8	0	0	2439	99.3	0	0
44.0 (150)	SLW	2034	94.3	0	0	2102	97.5	0	0	2138	99.2	0	0
44.0 (150)	75% Wood/[c] 25% HSE	1713	93.8	0	0	1773	97.0	373	70.0	1809	99.0	480	90.0
44.0 (150)	50% Wood/[c] 50% HSE	1799	94.0	139	13.5	1859	97.2	723	70.0	1895	99.1	930	90.0
117 (400)	50% Wood/[c] 50% HSE	5007	98.1	1612	58.5	5007	98.1	1930	70.0	5054	99.1	2480	90.0
44.0 (150)	50% Wood/[c] 50% LSW	1413	92.5	0	0	1473	96.5	160	70.0	1509	98.8	206	90.0
44.0 (150)	50% RDF/[c] 50% HSE	1967	94.5	233	20.7	2027	97.4	789	70.0	2063	99.1	1014	90.0
2.9 (10)	MSW	0	0	0	0	3.58	50.1	0	0	5.96	83.4	0	0
44.0 (150)	MSW	1141	94.9	0	0	1166	97.0	0	0	1184	99.0	0	0
117 (400)	MSW	3042	94.9	0	0	3109	97.0	0	0	3156	99.0	0	0
58.6 (200)	Bagasse	1585	87.8	0	0	1734	96.0	0	0	-[d]	-[d]	0	0

[a]Based on thermal input

[b]Wood - hog fuel (wood/bark mixture)
HAB - high ash bark
SLW - salt-laden wood
RDF - refuse derived fuel
MSW - municipal solid waste
HSE - high sulfur eastern coal
LSW - low sulfur western coal

[c]Average fuel mixture on a heat input basis

[d]Control level II was not evaluated for bagasse-fired boilers

TABLE 7-4. INCREMENTAL ANNUAL EMISSION REDUCTIONS ACHIEVED BY CONTROL LEVELS I AND II OVER BASELINE EMISSION LEVELS

Boiler Capacity[a] MW(10^6 Btu/hr)	Fuel[b]	Control Level I				Control Level II			
		PM		SO_2		PM		SO_2	
		Mg/yr Reduction	Percent Reduction	Mg/yr Reduction	Percent Reduction	Mg/yr Reduction	Percent Reduction	Mg/yr Reduction	Percent Reduction
8.8 (30)	Wood	32.2	75.0	0	0	39.3	91.7	0	0
220 (75)	Wood	80.1	75.0	0	0	98.1	91.7	0	0
44.0 (150)	Wood	161.4	75.0	0	0	197.1	91.7	0	0
117 (400)	Wood	429.0	75.0	0	0	524.3	91.7	0	0
44.0 (150)	HAB	68.4	56.1	0	0	104.1	85.3	0	0
44.0 (150)	SLW	68.4	56.1	0	0	104.1	85.3	0	0
44.0 (150)	75% Wood/[c] 25% HSE	60.4	53.0	373.0	70.0	96.1	84.3	479.7	90.0
44.0 (150)	50% Wood/[c] 50% HSE	60.4	53.0	584.0	65.3	96.1	84.3	791.0	88.5
117 (400)	50% Wood/[c] 50% HSE	0	0	318.0	27.8	47.6	49.9	868.0	75.9
44.0 (150)	50% Wood/[c] 50% LSW	60.4	53.0	160.4	70.0	96.1	84.3	206.1	90.0
44.0 (150)	50% RDF/[c] 50% HSE	60.4	53.0	556.0	62.2	96.1	84.3	781.0	87.4
2.9 (10)	MSW	3.58	50.1	0	0	5.96	83.4	0	0
44.0 (150)	MSW	25.1	41.2	0	0	42.9	70.6	0	0
117 (400)	MSW	66.7	41.2	0	0	114.3	70.6	0	0
58.6 (200)	Bagasse	149.5	67.6	0	0	-[d]	-[d]	0	0

[a]Based on thermal input

[b]Wood - hog fuel (wood/bark mixture)
HAB - high ash bark
SLW - salt-laden wood
RDF - refuse derived fuel
MSW - municipal solid waste
HSE - high sulfur eastern coal
LSW - low sulfur western coal

[c]Average fuel mixture on a heat input basis.

[d]Control level II was not evaluated for bagasse-fired boilers.

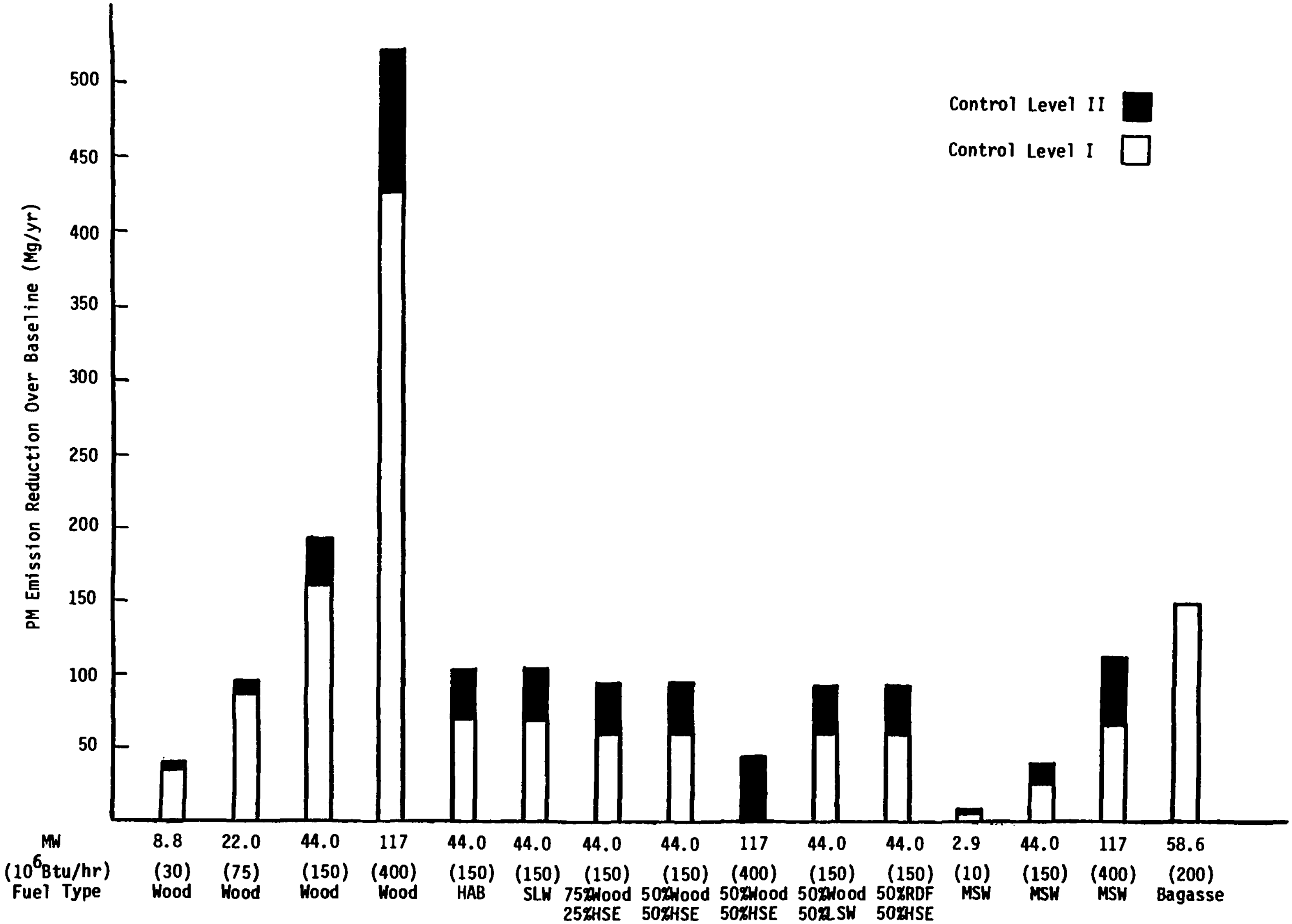


Figure 7-1. Incremental Annual PM Emission Reductions Achieved by Control Levels I and II Over Baseline Emission Levels.

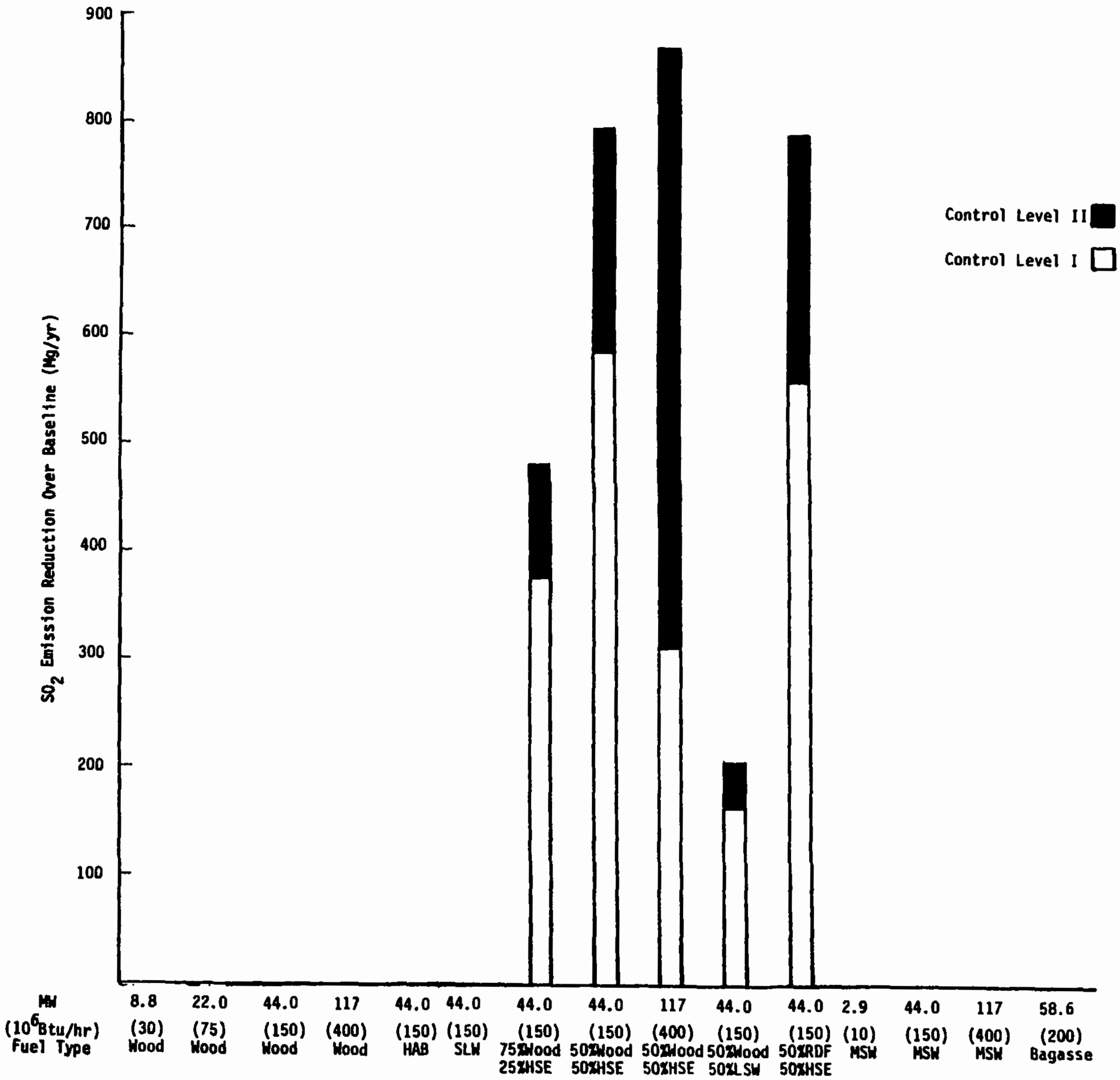


Figure 7-2. Incremental Annual SO_2 Emission Reductions Achieved By Control Levels I and II Over Baseline Emission Levels

The incremental PM emission reductions achieved at Control Levels I and II over the Baseline Control Level are presented in Table 7-4. These reductions are shown graphically in Figure 7-1. The 117 MW (400×10^6 Btu/hr) wood/HSE boiler shows no reduction for Control Level I because the Baseline Control Level for this boiler is as stringent as Control Level I. The lower baseline emission level for this boiler also results in the lower 49.9 percent reduction requirement for Control Level II over baseline. The rest of the model boilers show a range of 41.2 to 75.0 percent reduction at Control Level I and a range of 70.6 to 91.7 percent reduction at Control Level II.

Table 7-4 and Figure 7-2 show the incremental SO_2 emission reductions achieved at Control Levels I and II over the baseline controls for the model boilers cofiring coal (HSE or LSW) with nonfossil fuel. SO_2 Control Levels I and II for the cofiring cases are based on 70 percent and 90 percent reductions in uncontrolled SO_2 emissions respectively. The 117 MW wood/HSE boiler shows only a 27.8 percent incremental reduction at Control Level I and a 75.9 percent incremental reduction at Control Level II because the Baseline Control Level for this boiler already requires substantial SO_2 emission reductions. Reductions over the Baseline Control Level for the other cofired cases range from 62.2 to 70.0 percent for Control Level I and from 87.4 to 90.0 percent for Control Level II.

The nationwide impact on air pollution for applying PM Control Levels I and II to new NFFBs is shown in Table 7-5 and presented graphically in Figure 7-3. Nationwide annual emissions were calculated based on projected capacity growth of NFFBs in each fuel category. These projections were used to calculate the total capacity in 1990 of NFFBs affected by potential New Source Performance Standards. The size distribution of these boilers was determined from American Boiler Manufacturers Association (ABMA) sales data from 1970 to 1978 for wood- and bagasse-fired boilers, and from projections of plant capacities for MSW- and RDF-fired boilers.[1] The total capacity and size distributions were then used, along with model boiler emission rates and capacity factors to calculate the total annual particulate emission rate from affected NFFBs nationwide. The results are shown for each control

TABLE 7-5. NATIONAL PM EMISSIONS FROM NFFBs AFFECTED BY POTENTIAL NSPS IN 1990

Year	Fuel[c]	Total Installed[b] Heat Input Capacity GW(10^9Btu/hr)	Baseline Annual[a] Emissions Gg/yr(10^3ton/yr)	Control Level I[a]		Control Level II[a]	
				Annual Emissions Gg/yr(10^3ton/yr)	Percent Reduction Over Baseline	Annual Emissions Gg/yr(10^3ton/yr)	Percent Reduction Over Baseline
	Wood[d]	13.7 (46.6)	36.7 (40.4)	16.7 (18.4)	54.5	5.55 (6.12)	84.8
	MSW[e]	2.54 (8.68)	3.52 (3.88)	2.07 (2.28)	41.2	1.03 (1.14)	70.7
1990	MSW, ISW[f]	1.22 (4.16)	2.98 (3.28)	1.49 (1.64)	50.0	0.495 (0.546)	83.4
	RDF[g]	2.69 (9.17)	3.72 (4.10)	2.19 (2.41)	41.2	1.09 (1.20)	70.7
	Bagasse	2.79 (9.52)	10.5 (11.6)	3.40 (3.75)	67.7	-[h]	-
	Total	22.9 (78.1)	57.4 (63.3)	25.9 (28.5)	55.0	8.17 (9.01)	82.6

[a]Annual PM emissions are based on the maximum hourly boiler emission rates, annual capacity factors, and the total NFFB population affected by potential New Source Performance Standards in 1990.

[b]Includes only NFFBs affected by potential New Source Performance Standards. Shown here is the projected NFFB capacity installed in 1984 through 1990.

[c]Wood - all types of wood fuels
MSW - municipal solid waste
RDF - refuse derived fuel
ISW - industrial solid waste

[d]The high ash bark and salt-laden wood fuels were evaluated as model boiler cases to determine the sensitivity of emission control costs for wood-fired boilers to the ash and salt contents of wood fuels. For calculating the national environmental impacts of wood-fired boilers the wood fuel category is used to represent boilers burning all types of wood fuels.

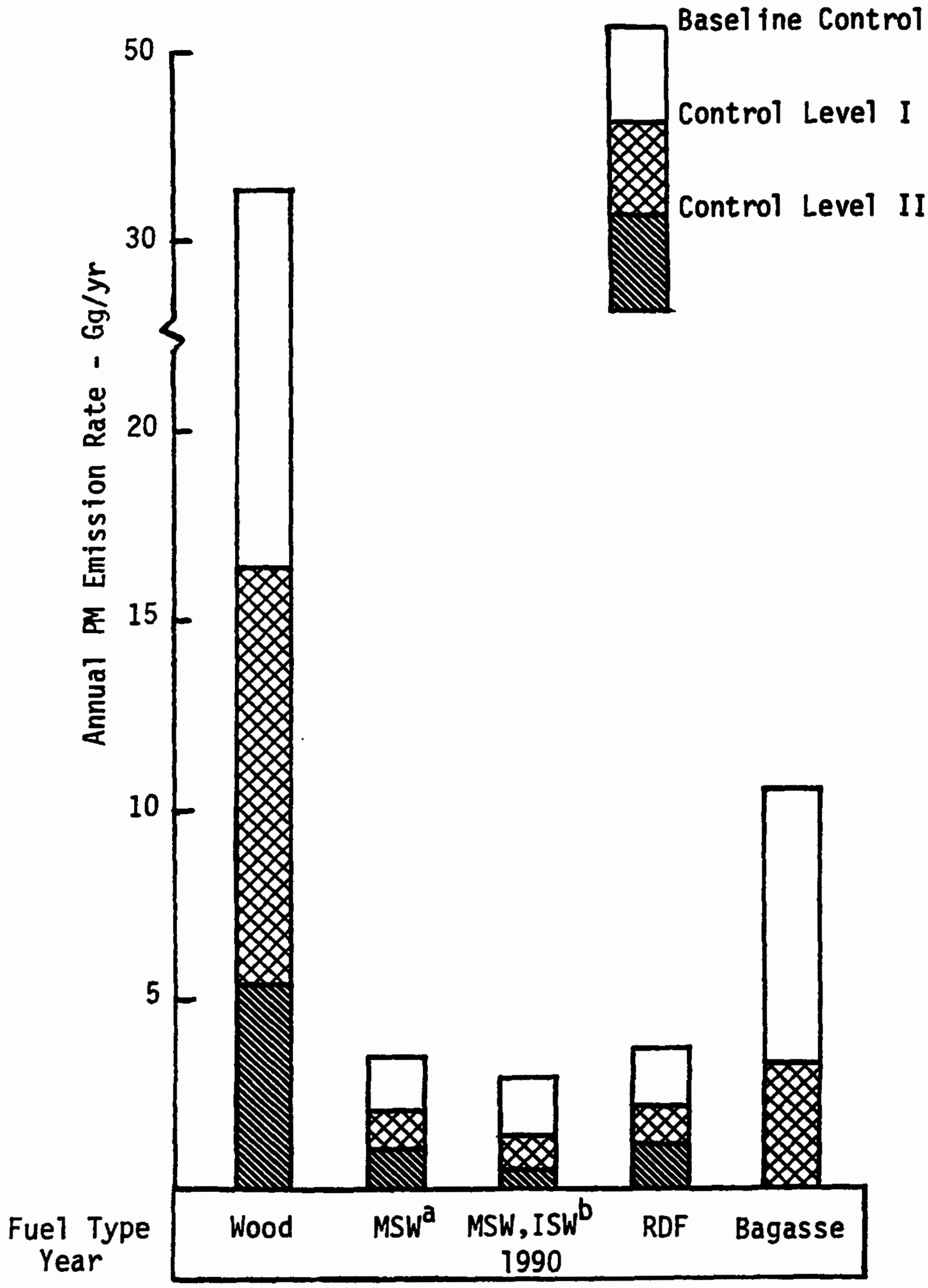
[e]Includes all MSW-fired boilers except small modular units.

[f]Includes only small modular MSW-fired and ISW-fired boilers.

[g]Based on RDF supplying 100 percent of the boiler heat input. For boilers firing 100 percent RDF the baseline control level and Control Level I are the same as the levels for a similar size MSW-fired boiler.

[h]A second control level was not evaluated for bagasse-fired boilers.

[i]For calculating national impacts, the Baseline Control Level is the average of State regulations shown in Chapter 3.



[a]Includes all MSW-fired boilers except small modular units.

[b]Includes only small modular MSW- and ISW-fired boilers.

Figure 7-3. National PM emissions from NFFBs affected by potential NSPS in 1990.

level as total annual emissions and the percent reduction of these emissions over baseline. The baseline control level used for wood to calculate nationwide impacts for wood-fired boilers is the average of existing State regulations shown in Chapter 3. This average level was used because it would more accurately represent the nationwide emissions than the 258 ng/J (0.6 lb/10^6 Btu) Baseline Control Level used to calculate individual model boiler impacts.

The boiler capacity projections are based simply on projections of the future use of nonfossil fuels. Sufficient data were not available to distinguish on a nationwide basis between the proportion of nonfossil fuel fired alone and that fired in combination with fossil fuel. Therefore, this analysis only includes the impacts of controlling emissions of particulate from the firing of nonfossil fuels. Since the future population of combination fuel boilers is not known, no national impacts for controlling SO_2 were estimated.

In this analysis, the wood fuel category was used to represent all types of wood fuels including high ash bark and salt-laden wood. The latter two fuels were only used as model boiler fuels to show the sensitivity of emission control costs to the ash and salt content of wood fuels. The inclusion of these fuels does not complicate the national emission impact analysis since the same control levels were evaluated for each of these fuels. Control Level I would reduce annual PM emissions from all nonfossil fuel fired boilers by 31.5 Gg/yr (34.7 x 10^3 tons/yr) below the Baseline Control Level by 1990. Control Level II would reduce the same annual PM emissions by 49.2 Gg/yr (54.2 x 10^3 tons/yr).

7.1.1.2 Dispersion Analysis. A dispersion analysis was performed to determine the ambient air impacts of the baseline and two alternate control levels on the model boilers. The dispersion analysis used the single source (CRSTER) model, which has generally been shown to be accurate within a factor of 2, for both urban and rural plants.[2] All model boilers were considered to be single point sources. The stack parameters for the model boilers used in the dispersion analysis are shown in Table 7-6. Model boilers 11, 12, 13, and 14 were analyzed assuming they were located in urban

TABLE 7-6. MODEL BOILER STACK PARAMETERS

Model Boiler Number	Boiler Capacity (thermal input)	Fuel[a]	Control Level[b] PM	Control Level[b] SO_2	Stack Height m (ft)	Stack Parameters: Flow Rate m^3/s (acfm)	Stack Parameters: Temp °C (°F)	Emissions From Stack[c]: PM kg/hr (lb/hr)	Emissions From Stack[c]: SO_2 kg/hr (lb/hr)
1a	8.8 MW	Wood	B	B	15.2 (50)	6.23 (13,200)	162.8 (325)	8.16 (18.00)	- -
1b	(30 x 10^6 Btu/hr)		I	B	15.2 (50)	5.24 (11,100)	65.6 (150)	2.04 (4.50)	- -
1c			II	B	15.2 (50)	5.24 (11,100)	65.6 (150)	0.680 (1.50)	- -
1d			II	B	15.2 (50)	6.23 (13,200)	162.8 (325)	0.680 (1.50)	- -
1e			II	B	15.2 (50)	6.23 (13,200)	162.8 (325)	0.680 (1.50)	- -
2a	22.0 MW	Wood	B	B	24.4 (80)	15.6 (33,100)	162.8 (325)	20.41 (45.00)	- -
2b	(75 x 10^6 Btu/hr)		I	B	24.4 (80)	13.2 (27,900)	65.5 (150)	5.10 (11.25)	- -
2c			II	B	24.4 (80)	13.2 (27,900)	65.6 (150)	1.70 (3.75)	- -
2d			II	B	24.4 (80)	15.6 (33,100)	162.8 (325)	1.70 (3.75)	- -
2e			II	B	24.4 (80)	15.6 (33,100)	162.8 (325)	1.70 (3.75)	- -
2f			II	B	24.4 (80)	15.6 (33,100)	162.8 (325)	1.70 (3.75)	- -
3a	44.0 MW	Wood	B	B	38.1 (125)	31.2 (66,100)	162.8 (325)	40.82 (90.00)	- -
3b	(150 x 10^6 Btu/hr)		I	B	38.1 (125)	26.3 (55,700)	65.5 (150)	10.21 (22.50)	- -
3c			II	B	38.1 (125)	26.3 (55,700)	65.6 (150)	3.40 (7.50)	- -
3d			II	B	38.1 (125)	31.2 (66,100)	162.8 (325)	3.40 (7.50)	- -
3e			II	B	38.1 (125)	31.2 (66,100)	162.8 (325)	3.40 (7.50)	- -
3f			II	B	38.1 (125)	31.2 (66,100)	162.8 (325)	3.40 (7.50)	- -
4a	117 MW	Wood	B	B	76.2 (250)	83.2 (176,200)	162.8 (325)	108.86 (240.0)	- -
4b	(400 x 10^6 Btu/hr)		I	B	76.2 (250)	70.1 (148,500)	65.6 (150)	27.22 (60.0)	- -
4c			II	B	76.2 (250)	70.1 (148,500)	65.6 (150)	9.07 (20.0)	- -
4d			II	B	76.2 (250)	83.2 (176,200)	162.8 (325)	9.07 (20.0)	- -
4e			II	B	76.2 (250)	83.2 (176,200)	162.8 (325)	9.07 (20.0)	- -
4f			II	B	76.2 (250)	83.2 (176,200)	162.8 (325)	9.07 (20.0)	- -
5a	44.0 MW	HAB	B	B	38.1 (125)	26.3 (55,700)	65.6 (150)	23.13 (51.00)	- -
5b	(150 x 10^6 Btu/hr)		I	B	38.1 (125)	26.3 (55,700)	65.6 (150)	10.21 (22.50)	- -
5c			II	B	38.1 (125)	31.2 (66,100)	162.8 (325)	3.40 (7.50)	- -
6a	44.0 MW	SLW	B	B	38.1 (125)	26.3 (55,700)	65.6 (150)	23.13 (51.00)	- -
6b	(150 x 10^6 Btu/hr)		I	B	38.1 (125)	26.3 (55,700)	65.6 (150)	10.21 (22.50)	- -
6c			II	B	38.1 (125)	31.2 (66,100)	162.8 (325)	3.40 (7.50)	- -
7a	44.0 MW	75% Wood/[d]	B	B	61.0 (200)	25.4 (53,900)	62.8 (145)	21.77 (48.00)	101.6 (224)
7b	(150 x 10^6 Btu/hr)	25% HSE	I	B	61.0 (200)	25.4 (53,900)	62.8 (145)	10.21 (22.50)	101.6 (224)
7c			I	I	61.0 (200)	25.4 (53,900)	62.8 (145)	10.21 (22.50)	30.5 (67.2)
7d			II	B	61.0 (200)	30.4 (64,400)	162.8 (325)	3.40 (7.50)	101.6 (224)
7e			II	B	61.0 (200)	30.4 (64,400)	162.8 (325)	3.40 (7.50)	101.6 (224)
7f			II	I	61.0 (200)	26.3 (55,800)	79.4 (175)	3.40 (7.50)	30.5 (67.2)
7g			II	II	61.0 (200)	25.4 (53,900)	62.8 (145)	3.40 (7.50)	10.2 (22.4)

See footnotes at end of table.

TABLE 7-6. (CONTINUED)

Model Boiler Number	Boiler Capacity (thermal input)	Fuel[a]	Control Level[b] PM	Control Level[b] SO_2	Stack Height m (ft)	Stack Parameters: Flow Rate m^3/s (acfm)	Stack Parameters: Temp °C (°F)	Emissions From Stack[c]: PM kg/hr (lb/hr)	Emissions From Stack[c]: SO_2 kg/hr (lb/hr)
8a	44.0 MW	50% Wood/[d]	B	B	61.0 (200)	24.6 (52,100)	60.0 (140)	21.77 (48.00)	170.1 (375)
8b	(150 x 10^6 Btu/hr)	50% HSE	I	B	61.0 (200)	24.6 (52,100)	60.0 (140)	10.21 (22.50)	170.1 (375)
8c			I	I	61.0 (200)	24.6 (52,100)	60.0 (140)	10.21 (22.50)	59.4 (131)
8d			I	II	61.0 (200)	24.6 (52,100)	60.0 (140)	10.21 (22.50)	19.7 (43.5)
8e			II	B	61.0 (200)	29.6 (62,700)	157.2 (315)	3.40 (7.50)	170.1 (375)
8f			II	I	61.0 (200)	25.7 (54,400)	79.4 (175)	3.40 (7.50)	59.4 (131)
8g			II	II	61.0 (200)	24.6 (52,100)	60.0 (140)	3.40 (7.50)	19.7 (43.5)
9a	117 MW	50% Wood/[d]	B	B	91.4 (300)	65.6 (139,000)	60 (140)	18.14 (40.00)	217.7 (480)
9b	(400 x 10^6Btu/hr)	50% HSE	I	I	91.4 (300)	65.6 (139,000)	60 (140)	18.14 (40.00)	157.9 (348)
9c			II	I	91.4 (300)	68.5 (145,000)	79.4 (175)	9.07 (20.00)	157.9 (348)
9d			II	II	91.4 (300)	65.6 (139,000)	60 (140)	9.07 (20.00)	52.6 (116)
10a	44.0 MW	50% Wood/[d]	B	B	61.0 (200)	25.0 (53,000)	60 (140)	21.77 (48.00)	43.5 (95.8)
10b	(150 x 10^6Btu/hr)	50% LSW	I	B	61.0 (200)	25.0 (53,000)	60 (140)	10.21 (22.50)	43.5 (95.8)
10c			I	I	61.0 (200)	25.0 (53,000)	60 (140)	10.21 (22.50)	13.0 (28.7)
10d			I	II	61.0 (200)	25.0 (53,000)	60 (140)	10.21 (22.50)	4.35 (9.58)
10e			II	B	61.0 (200)	30.0 (63,500)	162.8 (325)	3.40 (7.50)	43.5 (95.8)
10f			II	B	61.0 (200)	30.0 (63,500)	162.8 (325)	3.40 (7.50)	43.5 (95.8)
10g			II	I	61.0 (200)	26.2 (55,600)	79.4 (175)	3.40 (7.50)	13.0 (28.7)
10h			II	II	61.0 (200)	25.0 (53,000)	60 (140)	3.40 (7.50)	4.35 (9.58)
11a	44.0 MW	50% RDF/[d]	B	B	61.0 (200)	23.8 (50,400)	57.2 (135)	21.77 (48.00)	170.1 (375)
11b	(150 x 10^6Btu/hr)	50% HSE	I	I	61.0 (200)	23.8 (50,400)	57.2 (135)	10.21 (22.50)	63.5 (140)
11c			I	II	61.0 (200)	23.8 (50,400)	57.2 (135)	10.21 (22.50)	21.2 (46.7)
11d			II	I	61.0 (200)	23.8 (50,400)	57.2 (135)	3.40 (7.50)	63.5 (140)
11e			II	II	61.0 (200)	23.8 (50,400)	57.2 (135)	3.40 (7.50)	21.2 (46.7)
12a	2.9 MW	MSW	B	B	12.2 (40)	2.59 (5,480)	176.7 (350)	1.36 (3.00)	2.23 (4.92)
12b	(10 x 10^6Btu/hr)		I	B	12.2 (40)	2.10 (4,460)	60.0 (140)	0.680 (1.50)	2.23 (4.92)
12c			II	B	12.2 (40)	2.59 (5,480)	176.7 (350)	0.227 (0.50)	2.23 (4.92)
13a	44.0 MW	MSW	B	B	38.1 (125)	38.9 (82,400	176.7 (350)	11.57 (25.50)	33.5 (73.9)
13b	(150 x 10^6Btu/hr)		I	B	38.1 (125)	38.9 (82,400)	176.7 (350)	6.80 (15.00)	33.5 (73.9)
13c			II	B	38.1 (125)	38.9 (82,400)	176.7 (350)	3.40 (7.50)	33.5 (73.9)
14a	117 MW	MSW	B	B	76.2 (250)	103.5 (219,400)	176.7 (350)	30.84 (68.00)	89.4 (197)
14b	(400 x 10^6Btu/hr)		I	B	76.2 (250)	103.5 (219,400)	176.7 (350)	18.14 (40.00)	89.4 (197)
14c			II	B	76.2 (250)	103.5 (219,400)	176.7 (350)	9.07 (20.00)	89.4 (197)
15a	58.6 MW	Bagasse	B	B	38.1 (125)	44.3 (93,800)	176 (350)	56.25 (124.00)	- -
15b	(200 x 10^6Btu/hr)		I	B	38.1 (125)	37.4 (79,200)	68.3 (155)	18.14 (40.00)	- -

See footnotes at end of table.

Footnotes to Table 7-6:

[a]Wood - hog fuel (wood/bark mixture)
HAB - high ash bark
SLW - salt-laden wood
HSE - high sulfur eastern coal
LSW - low sulfur western coal
RDF - refuse derived fuel
MSW - municipal solid waste

[b]B refers to Baseline Control Level.
I refers to Control Level I.
II refers to Control Level II.

[c]Based on emission levels specified in Table 7-1.

[d]Average fuel mixture on a heat input basis.

areas whereas model plants 1 through 10 and 15 were assumed to be located in rural areas.

In this model 360 receptors were used to determine the downwind concentration of emissions. Ten receptors each were placed every 10 degrees around the emission point. The receptors on each radial were placed at varying distances from the emission source with three of the ten receptors located at 0.1, 1.0, and 10.0 km. The concentration at each receptor was calculated to determine the point of maximum concentration. Meteorological data for Baton Rouge, Louisiana, were used in this analysis. Because this dispersion analysis is based on meteorological data from one area it will not necessarily reflect the pollutant concentrations to be expected in all areas where NFFBs may be installed. However, this analysis is useful for showing relative impacts of alternative control levels.

For particulate matter the averaging times used were annual and 24-hours. For annual averages the highest concentrations at any receptor were determined. This is the "max mean concentration". For 24-hour averages the highest second-highest concentrations were determined. The "second max concentration" is derived by determining the second highest concentration at each receptor and selecting the highest of these second highest concentrations. In addition, the highest concentrations in any direction at 0.1, 1.0, and 10.0 km for annual averages and highest second-highest concentrations for 24-hour averages were determined. All averages are arithmetic means. The geometric mean concentrations can be assumed to be similar to the arithmetic mean. Sulfur dioxide concentrations are determined by the same method as PM concentrations except that the SO_2 analysis also used a 3-hour averaging time. The emission limits for model boilers 1a-4a and 13b-14b shown are not the same as the emission limits used in the dispersion analysis. Therefore, the ambient concentrations in the dispersion analysis were changed to correspond to the emission rates shown in Table 7-6.

Table 7-7 presents the annual maximum mean and the "second max concentration" for each model boiler for the different control levels and the distance downwind that they occur. The predicted concentrations are the

TABLE 7-7. DISPERSION MODELING RESULTS

Model Boiler No.	Fuel[a]	Pollutant	Control Level[b]-Emission Control System[c]	Ambient Concentration of Pollutant: Annual Maximum Mean/Distance Downwind $\mu g/m^3$	km	2nd Highest Maximum/Downwind Distance: 24 Hour Average $\mu g/m^3$	km	3 Hour Average $\mu g/m^3$	km
1a	Wood	PM	B - MC	1.68	0.6	17.0	0.5	-	
		SO_2	B - None	-	-	-	-	-	-
1b	Wood	PM	I - MC,WS	0.96	0.4	8.72	0.4	-	
		SO_2	B - None	-	-	-	-	-	-
1c	Wood	PM	II - MC,WS	0.32	0.4	2.91	0.4	-	
		SO_2	B - None	-	-	-	-	-	-
1d	Wood	PM	II - MC,FF	0.14	0.6	1.42	0.5	-	
		SO_2	B - None	-	-	-	-	-	-
1e	Wood	PM	II - MC,ESP	0.14	0.6	1.42	0.5	-	
		SO_2	B - None	-	-	-	-	-	-
2a	Wood	PM	B - MC	0.96	1.0	9.48	1.0	-	
		SO_2	B - None	-	-	-	-	-	-
2b	Wood	PM	I - MC,WS	0.52	0.8	4.67	0.8		
		SO_2	B - None	-	-	-	-	-	-
2c	Wood	PM	II - MC,WS	0.17	0.8	1.56	0.8	-	
		SO_2	B - None	-	-	-	-	-	-
2d	Wood	PM	II - MC,FF	0.08	1.0	0.79	1.0	-	
		SO_2	B - None	-	-	-	-	-	-
2e	Wood	PM	II - MC,ESP	0.08	1.0	0.79	1.0	-	
		SO_2	B - None	-	-	-	-	-	-
2f	Wood	PM	II - MC,EGB	0.08	1.0	0.79	1.0	-	
		SO_2	B - None	-	-	-	-	-	-
3a	Wood	PM	B - MC	0.72	1.8	7.32	1.8	-	
		SO_2	B - None	-	-	-	-	-	-
3b	Wood	PM	I - MC,WS	0.45	1.0	4.20	1.2	-	
		SO_2	B - None	-	-	-	-	-	-
3c	Wood	PM	II - MC,WS	0.15	1.0	1.40	1.2	-	
		SO_2	B - None	-	-	-	-	-	-
3d	Wood	PM	II - MC,FF	0.06	1.8	0.61	1.8	-	
		SO_2	B - None	-	-	-	-	-	-
3e	Wood	PM	II - MC,ESP	0.06	1.8	0.61	1.8	-	
		SO_2	B - None	-	-	-	-	-	-
3f	Wood	PM	II - MC,EGB	0.06	1.8	0.61	1.8	-	
		SO_2	B - None	-	-	-	-	-	-

See footnotes at end of table.

TABLE 7-7. (CONTINUED)

Model Boiler No.	Fuel[a]	Pollutant	Control Level[b]-Emission Control System[c]	Ambient Concentration of Pollutant: Annual Maximum Mean/Distance Downwind $\mu g/m^3$	km	2nd Highest Maximum/Downwind Distance: 24 Hour Average $\mu g/m^3$	km	3 Hour Average $\mu g/m^3$	km
4a	Wood	PM	B - MC	0.36	4.5	4.32	1.5	-	
		SO_2	B - None	-	-	-	-	-	-
4b	Wood	PM	I - MC,WS	0.19	2.5	2.58	1.1	-	
		SO_2	B - None	-	-	-	-	-	-
4c	Wood	PM	II - MC,WS	0.06	2.5	0.86	1.1	-	
		SO_2	B - None	-	-	-	-	-	-
4d	Wood	PM	II - MC,FF	0.03	4.2	0.36	1.5	-	
		SO_2	B - None	-	-	-	-	-	-
4e	Wood	PM	II - MC,ESP	0.03	4.5	0.36	1.5	-	
		SO_2	B - None	-	-	-	-	-	-
4f	Wood	PM	II - MC,EGB	0.03	4.2	0.36	1.5	-	
		SO_2	B - None	-	-	-	-	-	-
5a	HAB	PM	B - MC,WS	1.03	1.0	9.53	1.2	-	
		SO_2	B - None	-	-	-	-	-	-
5b	HAB	PM	I - MC,WS	0.45	1.0	4.20	1.2	-	
		SO_2	B - None	-	-	-	-	-	-
5c	HAB	PM	II - MC,FF	0.06	1.8	0.61	1.8	-	
		SO_2	B - None	-	-	-	-	-	-
6a	SLW	PM	B - MC,WS	1.03	1.0	9.53	1.2	-	
		SO_2	B - None	-	-	-	-	-	-
6b	SLW	PM	I - MC,WS	0.45	1.0	4.20	1.2	-	
		SO_2	B - None	-	-	-	-	-	-
6c	SLW	PM	II - MC,FF	0.06	1.8	0.61	1.8	-	
		SO_2	B - None	-	-	-	-	-	-
7a	75% Wood/[d]	PM	B - MC,WS	0.42	1.8	4.98	0.6	-	
	25% HSE	SO_2	B - None	1.96	1.8	23.2	0.6	107	0.5
7b	75% Wood/[d]	PM	I - MC,WS	0.20	1.8	2.33	0.6	-	
	25% HSE	SO_2	B - None	1.96	1.8	23.2	0.6	107	0.5
7c	75% Wood/[d]	PM	I - MC,WS	0.20	1.8	2.33	0.6	-	
	25% HSE	SO_2	I - FGD	0.59	1.8	6.98	0.6	32.2	0.5
7d	75% Wood	PM	II - MC,ESP	0.03	2.0	0.34	0.9	-	
	25% HSE	SO_2	B - None	0.97	2.0	10.1	0.9	51.1	0.6

See footnotes at end of table.

TABLE 7-7. (CONTINUED)

Model Boiler No.	Fuel[a]	Pollutant	Control Level[b]- Emission Control System[c]	Ambient Concentration of Pollutant: Annual Maximum Mean/ Distance Downwind $\mu g/m^3$	km	2nd Highest Maximum/Downwind Distance: 24 Hour Average $\mu g/m^3$	km	3 Hour Average $\mu g/m^3$	km
7e	75% Wood/[d]	PM	II - MC,FF	0.03	2.0	0.34	0.9	-	
	25% HSE	SO_2	B - None	0.97	2.0	10.1	0.9	51.1	0.6
7f	75% Wood/[d]	PM	II - MC,FF	0.06	1.6	0.64	0.8	-	
	25% HSE	SO_2	I - FGD-DS	0.50	1.6	5.70	0.8	26.0	0.5
7g	75% Wood	PM	II - MC,ESP	0.07	1.8	0.78	0.6	-	
	25% HSE	SO_2	II - FGD-WS	0.20	1.8	2.33	0.6	10.8	0.5
8a	50% Wood/[d]	PM	B - MC } WS	0.44	1.6	5.25	0.7	-	
	50% HSE	SO_2	B - FGD } WS	3.46	1.6	41.0	0.7	186	0.5
8b	50% Wood/[d]	PM	I - MC } WS	0.21	1.6	2.46	0.7	-	
	50% HSE	SO_2	B - FGD } WS	3.46	1.6	41.0	0.7	186	0.5
8c	50% Wood/[d]	PM	I - MC } WS	0.21	1.6	2.46	0.7	-	
	50% HSE	SO_2	I - FGD } WS	1.21	1.6	14.3	0.7	65.0	0.5
8d	50% Wood/[d]	PM	I - MC } WS	0.21	1.6	2.46	0.7	-	
	50% HSE	SO_2	II - FGD } WS	0.40	1.6	4.75	0.7	21.6	0.5
8e	50% Wood/[d]	PM	II - MC,FF	0.03	2.4	0.35	0.9	-	
	50% HSE	SO_2	B - FGD-DS[e]	1.73	2.4	17.5	0.9	89.2	0.6
8f	50% Wood/[d]	PM	II - MC,FF	0.03	2.4	0.35	0.9	-	
	50% HSE	SO_2	I - FGD-DS	1.73	2.4	17.5	0.9	89.2	0.6
8g	50% Wood/[d]	PM	II - MC,ESP	0.07	1.6	0.82	0.7	-	
	50% HSE	SO_2	II - FGD-WS	0.40	1.6	4.75	0.7	21.6	0.5
9a	50% Wood/[d]	PM	B - MC } WS	0.90	2.3	1.62	1.0	-	
	50% HSE	SO_2	B - FGD } WS	1.12	2.3	19.4	1.0	91.2	0.7
9b	50% Wood/[d]	PM	I - MC } WS	0.09	2.3	1.62	1.0	-	
	50% HSE	SO_2	B - FGD } WS	0.81	2.3	14.1	1.0	66.1	0.7
9c	50% Wood/[d]	PM	II - MC,FF	0.04	4.0	0.58	1.3	-	
	50% HSE	SO_2	I - FGD-DS	0.70	4.0	10.2	1.3	51.5	0.7
9d	50% Wood	PM	II - MC,ESP	0.05	2.3	0.81	1.0	-	
	50% HSE	SO_2	II - FGD,WS	0.27	2.3	4.69	1.0	22.0	0.7
10a	50% Wood/[d]	PM	B - MC,WS	0.43	1.4	5.24	0.6	-	
	50% LSW	SO_2	B - None	0.87	1.4	10.5	0.6	47.4	0.5
10b	50% Wood/[d]	PM	I - MC,WS	0.20	1.4	2.46	0.6	-	
	50% LSW	SO_2	B - None	0.87	1.4	10.5	0.6	47.4	0.5

See footnotes at end of table.

TABLE 7-7. (CONTINUED)

Model Boiler No.	Fuel[a]	Pollutant	Control Level[b] - Emission Control System[c]	Ambient Concentration of Pollutant: Annual Maximum Mean/Distance Downwind ($\mu g/m^3$)	(km)	2nd Highest Maximum/Downwind Distance: 24 Hour Average ($\mu g/m^3$)	(km)	3 Hour Average ($\mu g/m^3$)	(km)
10c	50% Wood/[d]	PM	I - MC }WS	0.20	1.4	2.46	0.6	-	
	50% LSW	SO_2	I - FGD	0.26	1.4	3.13	0.6	14.2	0.5
10d	50% Wood/[d]	PM	I - MC }WS	0.20	1.4	2.46	0.6	-	
	50% LSW	SO_2	II - FGD	0.09	1.4	1.05	0.6	4.74	0.5
10e	50% Wood/[d]	PM	II - MC,FF	0.03	2.0	0.34	0.9	-	
	50% LSW	SO_2	B - None	0.42	2.0	4.35	0.9	22.1	0.6
10f	50% Wood/[d]	PM	II - MC,ESP	0.03	2.0	0.34	0.9	-	
	50% LSW	SO_2	B - None	0.42	2.0	4.35	0.9	22.1	0.6
10g	50% Wood/[d]	PM	II - MC,FF	0.05	1.5	0.64	0.8	-	
	50% LSW	SO_2	I - FGD-DS	0.21	1.5	2.43	0.8	11.1	0.5
10h	50% Wood/[d]	PM	II - MC,ESP	0.07	1.4	0.82	0.6	-	
	50% LSW	SO_2	II - FGD-WS	0.09	1.4	1.05	0.6	4.74	0.5
11a	50% RDF/[d]	PM	B - }WS	0.63	2.0	5.48	0.7	-	
	50% HSE	SO_2	B - FGD	4.89	2.0	42.8	0.7	192	0.5
11b	50% RDF/[d]	PM	I - }WS	0.29	2.0	2.57	0.7	-	
	50% HSE	SO_2	I - FGD	1.82	2.0	16.0	0.7	71.7	0.5
11c	50% RDF/[d]	PM	I - }WS	0.29	2.0	2.57	0.7	-	
	50% HSE	SO_2	II - FGD	0.61	2.0	5.34	0.7	23.9	0.5
11d	50% RDF/[d]	PM	II - ESP	0.10	2.0	0.86	0.7	-	
	50% HSE	SO_2	I - FGD-WS	1.82	2.0	16.0	0.7	71.7	0.5
11e	50% RDF/[d]	PM	II - ESP	0.10	2.0	0.86	0.7	-	
	50% HSE	SO_2	II - FGD-WS	0.61	2.0	5.34	0.7	23.9	0.5
12a	MSW	PM	B - None	0.09	0.4	7.61	0.3	-	
		SO_2	B - None	1.54	0.4	12.5	0.3	29.3	0.2
12b	MSW	PM	I - WS	1.06	0.3	7.06	0.3	-	
		SO_2	B - None	3.47	0.3	23.1	0.3	75.6	0.5
12c	MSW	PM	II - FF	0.15	0.4	1.23	0.3	-	
		SO_2	B - None	1.54	0.4	12.5	0.3	29.3	0.2
13a	MSW	PM	B - ESP	0.18	2.4	1.90	2.2	-	
		SO_2	B - None	0.52	2.4	5.50	2.2	18.9	0.8
13b	MSW	PM	I - ESP	0.11	2.4	1.12	2.2	-	
		SO_2	B - None	0.52	2.4	5.50	2.2	18.9	0.8
13c	MSW	PM	II - ESP	0.05	2.4	0.56	2.2	-	
		SO_2	B - None	0.52	2.4	5.50	2.2	18.9	0.8

TABLE 7-7. (CONTINUED)

Model Boiler No.	Fuel[a]	Pollutant	Control Level[b]-Emission Control System[c]	Ambient Concentration of Pollutant: Annual Maximum Mean/Distance Downwind µg/m^3		2nd Highest Maximum/Downwind Distance: 24 Hour Average µg/m^3	km	3 Hour Average µg/m^3	km
14a	MSW	PM	B - ESP	0.09	5.0	1.05	1.6	-	
		SO_2	B - None	0.27	5.0	3.02	1.6	15.0	1.4
14b	MSW	PM	I - ESP	0.05	5.0	0.61	1.6	-	
		SO_2	B - None	0.27	5.0	3.02	1.6	15.0	1.4
14c	MSW	PM	II - ESP	0.03	5.0	0.31	1.6	-	
		SO_2	B - None	0.27	5.0	3.02	1.6	15.0	1.4
15a	Bagasse	PM	B - MC	0.65	2.4	6.80	1.7	-	
		SO_2	B - None	-		-		-	
15b	Bagasse	PM	I - WS	0.59	1.3	5.78	1.3	-	
		SO_2	B - None	-		-		-	

[a]Wood - hog fuel (wood/bark mixture)
HAB - high ash bark
SLW - salt-laden wood
HSE - high sulfur eastern coal
LSW - low sulfur western coal
RDF - refuse derived fuel
MSW - municipal solid waste

[b]B refers to Baseline Control Level.
I refers to Control Level I.
II refers to Control Level II.

[c]MC - muticyclone
WS - wet scrubber
FF - fabric filter
ESP - electrostatic precipitator
EGB - electrostatic gravel bed filter
FGD-WS - flue gas desulfurization; double alkali or lime wet scrubber
FGD-DS - flue gas desulfurization; lime dry scrubber
Control systems separated by a comma mean that both are used at the same time, not that either may be used independently. Mechanical collectors are included for fly ash reinjection on all of the boilers firing wood.

[d]Average fuel mixture on a heat input basis.

[e]The dry scrubber is sized to scrub only a portion of the flue gas.

concentrations which would occur in a pristine atmosphere and represent increases in ambient concentrations over background levels.

The primary national ambient air quality standards for particulate matter are 75 $\mu g/m^3$ for the annual geometric mean and 260 $\mu g/m^3$ for the maximum 24-hour concentration. The secondary standards are 60 $\mu g/m^3$ for the annual geometric mean and 150 $\mu g/m^3$ for the maximum 24-hour concentration. The annual mean cannot be exceeded, and the 24-hour average cannot be exceeded more than once a year.

The particulate matter annual maximum arithmetic mean concentration from the dispersion analysis ranged from 0.03 to 1.68 $\mu g/m^3$. Since the secondary standard stipulates the 24 hour maximum can be exceeded once a year, the dispersion analysis was used to determine the second highest 24-hour concentration to compare to the secondary standard. The second highest maximum 24 hour concentration of particulates ranged from 0.34 to 17.0 $\mu g/m^3$.

For particulate matter the annual maximum arithmetic mean ranges from 0.09 to 1.68 $\mu g/m^3$ for Baseline Controls, 0.05 to 1.06 $\mu g/m^3$ for Control Level I, and 0.03 to 0.32 $\mu g/m^3$ for Control Level II. These data show the ambient air benefits achieved by the addition of more efficient controls.

Since SO_2 control levels are only being evaluated for boilers cofiring nonfossil and fossil fuels, only model boilers 7 thru 11 are of interest in this analysis. Table 7-7 shows the annual "max mean concentration" and the "second max concentration" for 24-hour and 3-hour averaging times.

The primary national ambient air quality standards for sulfur oxides (SO_2) are 80 $\mu g/m^3$ for the annual arithmetic mean and 365 $\mu g/m^3$ for the 24-hour concentration which is not to be exceeded more than once a year. The secondary standard is 1300 $\mu g/m^3$ for the 3-hour maximum concentration which is not to be exceeded more than once a year.

The dispersion analysis shows that the max mean concentration varies from 0.81 to 4.89 $\mu g/m^3$ at Baseline Control, 0.21 to 1.82 $\mu g/m^3$ at Control Level I, and 0.09 to 0.61 $\mu g/m^3$ at Control Level II. These data show the favorable ambient air impact of SO_2 controls on the cofired model boilers.

These data show a definite beneficial impact on ambient air quality due to more efficient controls for PM and SO_2. These data also show that for similar control levels, dry control systems such as baghouses, ESPs, and EGBs, result in smaller ground level pollutant concentrations than do wet control systems. This is caused by the increased plume rise resulting from dry control systems. In some cases part of the difference in ambient concentrations for alternative control levels is attributable to this phenomenon.

The values presented were determined assuming no background concentration of pollutants. Therefore, any background concentration of pollutants at the emission source should be added to the reported concentrations to obtain the ambient pollutant concentrations after installation of a nonfossil fuel fired boiler. However, application of an efficient control system will result in the NFFB having a small ambient pollutant impact.

7.1.2 Secondary Air Impacts

Secondary air emissions will result from power plant boilers supplying electricity to the nonfossil fuel boiler control devices, since the power required to operate the control equipment will ultimately result in greater emissions at the electric power generation facility. For NFFBs used to cogenerate steam and electricity, power requirements of the control systems will result in increased emissions from the NFFB itself. For each model boiler, Table 7-8 presents the estimated incremental amounts of PM and SO_2 emissions generated at a coal-fired electric power generation facility. PM and SO_2 emissions at the power generating facility were calculated assuming that the power boilers comply with the New Source Performance Standard for utility boilers.[3] Table 7-8 shows that the incremental emissions caused by power requirements of the control systems are small when compared to the emission reductions caused by those control systems.

For example, a 44 MW (150×10^6 Btu/hr) NFFB burning 50% wood/50% HSE with PM and SO_2 emissions controlled to Control Level II would have a 291 kW electrical demand for pollution control equipment. This demand would result in the following incremental air emissions from the power boiler; PM - 0.21 Mg/yr, SO_2 - 5.20 Mg/yr, and NO_x - 4.16 Mg/yr. However, these

TABLE 7-8. SECONDARY AIR EMISSIONS DUE TO ELECTRICAL DEMANDS OF CONTROL SYSTEMS

Model Boiler Number	Boiler Capacity (thermal input)	Fuel[a]	Control Level[b] PM	Control Level[b] SO_2	Emission[c] Control System	Electrical[f] Energy Consumed kW	Power Generating Source: Heat Input[g] Power Boiler MW (10^6Btu/hr)	Power Generating Source: Emissions From[h] Power Boiler (Mg/yr) PM	Emissions From[h] Power Boiler (Mg/yr) SO_2	Emissions From[h] Power Boiler (Mg/yr) NO_x	Emssions Reduced[i] From Uncontrolled NFFB (Mg/yr) PM	Emssions Reduced[i] From Uncontrolled NFFB (Mg/yr) SO_2
1a	8.8 MW	Wood	B	B	MC	18.4	0.05 (0.18)	0.01	0.32	0.26	306	-
1b	(30 x 10^6Btu/hr)		I	B	MC,WS	64.9	0.19 (0.65)	0.05	1.16	0.93	338	-
1c			II	B	MC,WS	102	0.30 (1.02)	0.07	1.82	1.46	345	-
1d			II	B	MC,FF	41.3	0.12 (0.41)	0.03	0.73	0.59	345	-
1e			II	B	MC,ESP	42.0	0.12 (0.42)	0.03	0.75	0.60	345	-
2a	22.0 MW	Wood	B	B	MC	42.8	0.13 (0.43)	0.03	0.77	0.62	766	-
2b	(75 x 10^6Btu/hr)		I	B	MC,WS	159	0.47 (1.59)	0.11	2.84	2.27	846	-
2c			II	B	MC,WS	252	0.74 (2.52)	0.18	4.51	3.60	864	-
2d			II	B	MC,FF	101	0.30 (1.01)	0.07	1.81	1.44	864	-
2e			II	B	MC,ESP	102	0.30 (1.02)	0.07	1.82	1.46	864	-
2f			II	B	MC,EGB	113	0.33 (1.13)	0.08	2.02	1.62	864	-
3a	44.0 MW	Wood	B	B	MC	92.9	0.27 (0.93)	0.07	1.66	1.33	1530	-
3b	(150 x 10^6Btu/hr)		I	B	MC,WS	314	0.92 (3.14)	0.22	5.61	4.49	1690	-
3c			II	B	MC,WS	500	1.47 (5.00)	0.36	8.94	7.15	1730	-
3d			II	B	MC,FF	201	0.59 (2.01)	0.14	3.59	2.87	1730	-
3e			II	B	MC,ESP	197	0.58 (1.97)	0.14	3.52	2.82	1730	-
3f			II	B	MC,EGB	219	0.64 (2.19)	0.16	3.92	3.13	1730	-
4a	117 MW	Wood	B	B	MC	241.1	0.71 (2.41)	0.17	4.31	3.45	4080	-
4b	(400 x 10^6Btu/hr)		I	B	MC,WS	834	2.44 (8.34)	0.60	14.9	11.9	4510	-
4c			II	B	MC,WS	1330	3.90 (13.30)	0.95	23.8	19.0	4610	-
4d			II	B	MC,FF	534	1.57 (5.34)	0.38	9.55	7.64	4610	-
4e			II	B	MC,ESP	524	1.54 (5.24)	0.37	9.37	7.49	4610	-
4f			II	B	MC,EGB	601	1.76 (6.01)	0.43	10.8	8.60	4610	-
5a	44.0 MW	HAB	B	B	MC,WS	206	0.60 (2.06)	0.15	3.68	2.95	2340	-
5b	(150 x 10^6Btu/hr)		I	B	MC,WS	336	0.98 (3.36)	0.24	6.01	4.81	2400	-
5c			II	B	MC,FF	209	0.61 (2.09)	0.15	3.74	2.99	2440	-
6a	44.0 MW	SLW	B	B	MC,WS	314	0.92 (3.14)	0.22	5.61	4.49	2030	-
6b	(150 x 10^6Btu/hr)		I	B	MC,WS	500	1.47 (5.00)	0.36	8.94	7.15	2100	-
6c			II	B	MC,FF	201	0.59 (2.01)	0.14	3.59	2.87	2140	-
7a	44.0 MW	75% Wood/[d]	B	B	MC,WS	177	0.52 (1.77)	0.13	3.16	2.53	1710	-
7b	(150 x 10^6Btu/hr)	25% HSE	I	B	MC,WS	303	0.89 (3.03)	0.22	5.42	4.33	1770	-
7c			I	I	MC,FGD-WS	306	0.90 (3.06)	0.22	5.47	4.38	1770	373
7d			II	B	MC,ESP	180	0.53 (1.80)	0.13	3.22	2.57	1810	-
7e			II	B	MC,FF	195	0.57 (1.95)	0.14	3.49	2.79	1810	-
7f			II	I	MC,FGD-DS,FF	251	0.74 (2.51)	0.18	4.49	3.59	1810	373
7g			II	II	MC,ESP,FGD-WS	311	0.91 (3.11)	0.22	5.56	4.45	1810	480

See footnotes at end of table.

TABLE 7-8. (CONTINUED)

Model Boiler Number	Boiler Capacity (thermal input)	Fuel[a]	Control Level[b] PM	Control Level[b] SO_2	Emission[c] Control System	Electrical[f] Energy Consumed kW	Power Generating Source: Heat Input[g] Power Boiler MW (10^6Btu/hr)	Emissions From[h] Power Boiler (Mg/yr) PM	SO_2	NO_x	Emssions Reduced[i] From Uncontrolled NFFB (Mg/yr) PM	SO_2
8a	44.0 MW	50% Wood/[d]	B	B	MC,FGD-WS	178	0.52 (1.78)	0.13	3.18	2.55	1800	139
8b	(150 x 10^6 Btu/hr)	50% HSE	I	B	MC,FGD-WS	296	0.87 (2.96)	0.21	5.29	4.23	1860	139
8c			I	I	MC,FGD-WS	303	0.89 (3.03)	0.22	5.42	4.33	1860	723
8d			I	II	MC,FGD-WS	306	0.90 (3.06)	0.22	5.47	4.37	1860	930
8e			II	B	MC,FGD-DS,FF[e]	218	0.64 (2.18)	0.16	3.90	3.12	1900	139
8f			II	I	MC,FGD-DS,FF	254	0.74 (2.54)	0.18	4.54	3.63	1900	723
8g			II	II	MC,ESP,FGD-WS	291	0.85 (2.91)	0.21	5.20	4.16	1900	930
9a	117 MW	50% Wood/[d]	B	B	MC,FGD-WS	831	2.44 (8.31)	0.59	14.9	11.9	5010	1610
9b	(400 x 10^6Btu/hr)	50% HSE	I	I	MC,FGD-WS	834	2.44 (8.34)	0.60	14.9	11.9	5010	1930
9c			II	I	MC,FGD-DS,FF	601	1.76 (6.01)	0.43	10.7	8.60	5050	1930
9d			II	II	MC,ESP,FGD-WS	762	2.23 (7.62)	0.54	13.6	10.9	5050	2480
10a	44.0 MW	50% Wood/[d]	B	B	MC,WS	161	0.47 (1.61)	0.12	2.88	2.30	1410	-
10b	(150 x 10^6Btu/hr)	50% LSW	I	B	MC,WS	288	0.84 (2.88)	0.21	5.15	4.12	1470	-
10c			I	I	MC,FGD-WS	288	0.84 (2.88)	0.21	5.15	4.12	1470	160
10d			I	II	MC,FGD-WS	288	0.84 (2.88)	0.21	5.15	4.12	1470	206
10e			II	B	MC,FF	193	0.57 (1.93)	0.14	3.45	2.76	1510	-
10f			II	B	MC,ESP	199	0.58 (1.99)	0.14	3.56	2.85	1510	-
10g			II	I	MC,FGD-DS,FF	246	0.72 (2.46)	0.18	4.40	3.52	1510	160
10h			II	II	MC,ESP,FGD-WS	325	0.95 (3.25)	0.23	5.81	4.65	1510	206
11a	44.0 MW	50% RDF/[d]	B	B	FGD-WS	201	0.59 (2.01)	0.14	3.59	2.87	1970	233
11b	(150 x 10^6Btu/hr)	50% HSE	I	I	FGD-WS	277	0.81 (2.77)	0.20	4.95	3.96	2030	789
11c			I	II	FGD-WS	279	0.81 (2.79)	0.20	4.99	3.99	2030	1015
11d			II	I	ESP,FGD-WS	223	0.65 (2.23)	0.16	3.99	3.19	2060	789
11e			II	II	ESP,FGD-WS	226	0.66 (2.26)	0.16	4.04	3.23	2060	1010
12a	2.9 MW	MSW	B	B	-	-	-	-	-	-	-	-
12b	(10 x 10^6Btu/hr)		I	B	WS	28.0	0.08 (0.28)	0.02	0.05	0.40	3.58	-
12c			II	B	FF	11.1	0.03 (0.11)	0.01	0.20	0.16	5.96	-
13a	44.0 MW	MSW	B	B	ESP	93.7	0.31 (1.05)	0.08	1.88	1.50	1140	-
13b	(150 x 10^6Btu/hr)		I	B	ESP	128	0.38 (1.28)	0.09	2.29	1.83	1160	-
13c			II	B	ESP	192	0.51 (1.75)	0.13	3.13	2.50	1190	-
14a	117 MW	MSW	B	B	ESP	248	0.81 (2.78)	0.20	4.97	3.98	3040	-
14b	(400 x 10^6Btu/hr)		I	B	ESP	338	0.99 (3.38)	0.24	6.04	4.83	3110	-
14c			II	B	ESP	509	1.36 (4.63)	0.33	8.28	6.62	3170	-
15a	58.6 MW	Bagasse	B	B	MC	136	0.40 (1.36)	0.07	1.82	1.46	1580	-
15b	(200 x 10^6Btu/hr)		I	B	WS	183	0.54 (1.83)	0.10	2.45	1.96	1730	-

See footnotes at end of table.

Footnotes to Table 7-8:

[a]Wood - hog fuel (wood/bark mixture)
HAB - high ash bark
SLW - salt-laden wood
HSE - high sulfur eastern coal
LSW - low sulfur western coal
RDF - refuse derived fuel
MSW - municipal solid waste

[b]B refers to Baseline Control Level.
I refers to Control Level I.
II refers to Control Level II.

[c]MC - multicyclone
WS - wet scrubber
FF - fabric filter
ESP - electrostatic precipitator
EGB - electrostatic gravel bed filter
FGD-WS - flue gas desulfurization; double alkali or lime wet scrubber
FGD-DS - flue gas desulfurization; lime dry scrubber
Control systems separated by a comma mean that both are used at the same time, not that either may be used independently. Mechanical collectors are included for fly ash reinjection on all of the boilers firing wood.

[d]Average fuel mixture on a heat input basis.

[e]The dry scrubber is sized to scrub only a portion of the flue gas.

[f]Amount of electrical energy consumed by the control equipment

[g]Heat input required at the utility power boiler to produce the electrical energy consumed by the NFFB control equipment. Calculations are based on a fuel thermal input of 10,000 Btu to produce one KWH of electricity.

[h]Assumes a coal-fired utility boiler in compliance with the utility NSPS (Subpart Da). Emission limits are as follows: PM-0.03 lb/10^6Btu, NO_x-0.60 lb/10^6Btu, SO_2-90% removal with 1.2 lb/10^6Btu ceiling (assume 0.75 lb/10^6Btu is average control level). A 45% load factor is assumed for the bagasse boiler and a 60% load factor for all other nonfossil fuel fired boilers.

[i]The nonfossil fuel fired boiler emission reductions are taken from Table 7-3.

incremental emissions are far less than the 1900 Mg/yr of PM and 930 Mg/yr of SO_2 reduced by the NFFB control equipment. The same boiler firing 100 percent wood and controlled to Control Level II would, for the most energy demanding case considered, result in the following incremental air emissions from the utility power boiler; PM-0.36 Mg/yr, SO_2 - 8.94 Mg/yr, and NO_x - 7.15 Mg/yr. These incremental emissions are also smaller in magnitude than the 1730 Mg/yr of PM controlled by the NFFB control equipment.

7.2 LIQUID WASTE IMPACTS

Water pollution impacts or the need for additional water treatment can result from controlling nonfossil fuel boiler air emissions if the control technologies used to achieve the various control levels examined produce aqueous discharge streams.

Dry particulate controls (ESP, FF, EGB, MC) do not result in water discharges, but incremental water pollution impacts from PM controls can result if the collected particulate material is sluiced to disposal ponds. However, the sluiced ash stream from a PM control device can be treated in existing facilities, along with the boiler bottom ash stream, to remove the suspended solids and the water reused.

Wet scrubbers used for particulate control will also produce an aqueous stream. The water in a wet scrubbing system is usually recycled with provisions for make-up and blowdown to prevent the suspended solids concentration from becoming high enough to plug the scrubber nozzles or erode the internal components. However, this blowdown stream may be treated in a thickener or settling pond and the water reused. The solids are removed from the system in the form of a sludge. In any case there need not be an aqueous discharge to the environment as a result of PM emission control.

The control of SO_2 by FGD can result in liquid waste discharges, though dry scrubbing processes are designed not to generate liquid wastes. However, even wet scrubbing processes such as dual alkali (DA), lime, and limestone systems can be designed on a closed loop basis so that the only water losses during normal operation occur with the sludge going to landfill.[4] Any purging of these systems due to water imbalances or other operating upsets, system blowdown to prevent scaling, or operator error will result in discharge of an aqueous waste stream which can be contained and treated. However, during normal operation, there should be no water pollution impact from lime, limestone, or double alkali FGD systems designed on a closed loop basis.[4] Some FGD systems, such as sodium scrubbing systems, may result in an aqueous discharge stream which must be treated and disposed of properly. The situation is not discussed any further in this document since an SO_2 regulation need not result in a liquid waste impact.

7.3 SOLID WASTE IMPACTS

Nonfossil and combination fuel boiler air pollution control techniques produce two main types of solid wastes: fly ash collected by the PM control devices, and waste solids (both sludge and dry scrubbing products) from the control of SO_2 emissions. In this section the impacts of the incremental solid wastes produced from PM and SO_2 controls are discussed by considering the following:

- solid waste quantities and characteristics,
- waste treatment and disposal,
- applicable regulations,
- national solid waste impacts of potential NSPS.

7.3.1 Solid Waste Quantities and Characteristics

The fly ash from NFFBs is commonly over 50 percent unburned combustibles, mainly carbon. Because of this high combustible content the fly ash from NFFBs will burn more easily than fly ash from fossil fuel boilers. Care must be taken when handling this fly ash to prevent fires. In addition the fly ash contains inorganic compounds. These compounds include elements such as barium, iron, magnesium, titanium, sodium, phosphorus, sulfur, silicon, and traces of 50 to 100 other elements. The amounts of these elements will vary with the source and type of fuel burned.

The sludges from wet scrubbers used for particulate control may contain over 50 percent moisture. Dry particulate controls such as ESPs, FFs, and EGBs result in a collected fly ash containing little moisture.

Dual alkali scrubber sludges are composed primarily of calcium sulfite/sulfate solids. Also present are dissolved sodium salts and trace elements (e.g., lead, arsenic and cadmium), which may contaminate the groundwaters and surface waters due to runoff and leaching from sludge disposal sites (see Section 7.3.2). The chemical composition and concentration of FGD sludge liquors vary with the different fuel types used in cofired NFFBs. When a particulate collection device is not used upstream of the FGD system and the FGD system is being used to control both SO_2 and PM emissions, the trace element concentrations in the scrubber sludge are increased due to the addition of fly ash to the sludge.

The dry solid waste produced from spray-drying FGD processes consists primarily of calcium or sodium salts, depending upon the type of alkali used as the SO_2 sorbent. Significant quantities of fly ash will also be present because the PM collection device is located downstream of the spray dryer and removes fly ash along with the spray dried solids.

Table 7-9 shows the quantities of solid wastes produced at different control levels for each of the model boilers. Also shown on this table are the types of PM and SO_2 control techniques used to achieve the indicated control levels. For PM control, the MC, ESP, FF, and EGB control techniques result in the collection of a dry particulate fly ash. The WS control technique results in the production of a particulate sludge. In Table 7-9 the sludge from particulate scrubbers contains 30 percent solids. For SO_2 control with a lime or double alkali FGD system, the sludge concentration is 50 percent solids. Solid wastes shown for the cases involving dry scrubbing control are the combined amounts of fly ash, sulfate/sulfite salts, and unreacted sorbent collected by the PM control device downstream of the SO_2 dry scrubbing system. Sludge quantities presented for the combined SO_2/PM systems are based on a sludge concentration of 50 percent solids. For example, data presented in this table show that for the 44 MW (150×10^6 Btu/hr) 50% wood/50% HSE fired boiler, solid wastes (combined dry solids and sludge) increase by 2990 Mg/yr in going from the baseline to Control Level II for PM and SO_2 control.

7.3.2 Waste Treatment and Disposal

Ponding and landfilling are currently the primary methods of disposal for collected fly ash (including dry solids and sludge). Current State and

TABLE 7-9. QUANTITIES OF SOLID WASTE GENERATED FROM MODEL BOILER CONTROL SYSTEMS

Model Boiler Number	Boiler Capacity (thermal input)	Fuel[a]	Control Level[b]		Emission Control System[c]	Amount of Solid Waste Generated: Solids From Dry Particulate Controls[f,j]		Amount of Solid Waste Generated: Sludge From Wet Scrubber[g]	
			PM	SO_2		Mg/yr	tons/yr	Mg/yr	tons/yr
1a	8.8 MW	Wood	B	B	MC	180	199	-	-
1b	(30×10^6 Btu/hr)		I	B	MC,WS	154	169	195	215
1c			II	B	MC,WS	154	169	219	242
1d			II	B	MC,FF	219	242	-	-
1e			II	B	MC,ESP	219	242	-	-
2a	22.0 MW	Wood	B	B	MC	451	497	-	
2b	(75×10^6 Btu/hr)		I	B	MC,WS	384	423	489	539
2c			II	B	MC,WS	384	423	548	604
2d			II	B	MC,FF	548	604	-	-
2e			II	B	MC,ESP	548	604	-	-
2f			II	B	MC,EGB	548	604	-	-
3a	44.0 MW	Wood	B	B	MC	901	993		
3b	(150×10^6 Btu/hr)		I	B	MC,WS	768	846	977	1080
3c			II	B	MC,WS	768	846	1100	1210
3d			II	B	MC,FF	1100	1210	-	-
3e			II	B	MC,ESP	1100	1210	-	-
3f			II	B	MC,EGB	1100	1210	-	-
4a	117 MW	Wood	B	B	MC	2406	2652	-	-
4b	(400×10^6 Btu/hr)		I	B	MC,WS	2050	2260	2610	2870
4c			II	B	MC,WS	2050	2260	2930	3220
4d			II	B	MC,FF	2930	3220	-	-
4e			II	B	MC,ESP	2930	3220	-	-
4f			II	B	MC,EGB	2930	3220	-	-
5a	44.0 MW	HAB	B	B	MC,WS	1340	1480	1220	1350
5b	(150×10^6 Btu/hr)		I	B	MC,WS	1340	1480	1450	1600
5c			II	B	MC,FF	1810	2000	-	-
6a	44.0 MW	SLW	B	B	MC,WS	775	854	2110	2330
6b	(150×10^6 Btu/hr)		I	B	MC,WS	775	854	2340	2580
6c			II	B	MC,FF	1510	1670	-	-
7a	44.0 MW	75% Wood/[d]	B	B	MC,WS	994	1100	834	920
7b	(150×10^6 Btu/hr)	25% HSE	I	B	MC,WS	994	1100	1030[h]	1140[h]
7c			I	I	MC,FGD-WS	994	1100	2110[h]	2320[h]
7d			II	B	MC,ESP	1340	1480	-	-
7e			II	B	MC,FF	1340	1480	-	-
7f			II	I	MC,FGD-DS,FF	2380[i]	2630[i]	-	-
7g			II	II	MC,ESP,FGD-WS	1340	1480	1920[h]	2110[h]
8a	44.0 MW	50% Wood/[d]	B	B	MC,FGD-WS	1220	1340	1090[h]	1200[h]
8b	(150×10^6 Btu/hr)	50% HSE	I	B	MC,FGD-WS	1220	1340	1220[h]	1340[h]
8c			I	I	MC,FGD-WS	1220	1340	3550[h]	3910[h]
8d			I	II	MC,FGD-WS	1220	1340	4380[h]	4830[h]
8e			II	B	MC,FGD-DS,FF[e]	1970[i]	2170[i]	-	-
8f			II	I	MC,FGD-DS,FF	3600[i]	3970[i]	-	-
8g			II	II	MC,ESP,FGD-WS	1580	1740	3720[h]	4100[h]
9a	117 MW	50% Wood/[d]	B	B	MC,FGD-WS	3240	3570	8300[h]	9150[h]
9b	(400×10^6 Btu/hr)	50% HSE	I	I	MC,FGD-WS	3240	3570	9560[h]	10500[h]
9c			II	I	MC,FGD-DS,FF	9610[i]	10600[i]	-	-
9d			II	II	MC,ESP,FGD-WS	4470	4930	11900[h]	13100[h]

See footnotes at end of table.

TABLE 7-9. (CONTINUED)

Model Boiler Number	Boiler Capacity (thermal input)	Fuel[a]	Control Level[b] PM	Control Level[b] SO_2	Emission[b] Control System	Amount of Solid Waste Generated: Solids From Dry Particulate Controls[f,j] Mg/yr	Solids From Dry Particulate Controls[f,j] tons/yr	Sludge From Wet Scrubber[g] Mg/yr	Sludge From Wet Scrubber[g] tons/yr
10a	44.0 MW	50% Wood/[d]	B	B	MC,WS	906	999	632	696
10b	(150×10^6 Btu/hr)	50% LSW	I	B	MC,WS	906	999	834	920
10c			I	I	MC,FGD-WS	906	999	1140[h]	1260[h]
10d			I	II	MC,FGD-WS	906	999	1330[h]	1470[h]
10e			II	B	MC,FF	1190	1310	-	-
10f			II	B	MC,ESP	1190	1310	-	-
10g			II	I	MC,FGD-DS,FF	1640[i]	1810[i]	-	-
10h			II	II	MC,ESP,FGD-WS	1190	1310	830[h]	915[h]
11a	44.0 MW	50% RDF/[d]	B	B	FGD-WS	-	-	4850[h]	5350[h]
11b	(150×10^6 Btu/hr)	50% HSE	I	I	FGD-WS	-	-	7200[h]	7940[h]
11c			I	II	FGD-WS	-	-	8100[h]	8930[h]
11d			II	I	ESP,FGD-WS	2060	2270	3150	3470
11e			II	II	ESP,FGD-WS	2060	2270	4050	4460
12a	2.9 MW	MSW	B	B	-	-	-	-	-
12b	(10×10^6 Btu/hr)		I	B	WS	-	-	35.8	39.4
12c			II	B	FF	5.96	6.57	-	-
13a	44.0 MW	MSW	B	B	ESP	1140	1260	-	-
13b	(150×10^6 Btu/hr)		I	B	ESP	1160	1280	-	-
13c			II	B	ESP	1190	1310	-	-
14a	117 MW	MSW	B	B	ESP	3040	3350	-	-
14b	(400×10^6 Btu/hr)		I	B	ESP	3110	3430	-	-
14c			II	B	ESP	3170	3490	-	-
15a	58.6 MW	Bagasse	B	B	MC	1580	1750	-	-
15b	(200×10^6 Btu/hr)		I	B	WS	-	-	5780	6370

[a]Wood - hog fuel (wood/bark mixture)
HAB - high ash bark
SLW - salt-laden wood
HSE - high sulfur eastern coal
LSW - low sulfur western coal
RDF - refuse derived fuel
MSW - municipal solid waste

[b]B refers to Baseline control level.
I refers to Control Level I.
II refers to Control Level II.

[c]MC - mechanical collector
WS - wet scrubber
FF - fabric filter
ESP - electrostatic precipitator
EGB - electrostatic gravel bed filter
FGD-WS - flue gas desulfurization; double alkali or lime wet scrubber
FGD-DS - flue gas desulfurization; lime dry scrubber
Control systems separated by a comma mean that both are used at the same time, not that either may be used independently. mechanical collectors are included for fly ash reinjection on all of the boilers firing wood.

[d]Average fuel mixture on a heat input basis.

[e]The dry scrubber is sized to scrub only a portion of the flue gas.

[f]Weight on a dry basis.

[g]Weight based on 30 percent solids (except as noted). Sludge from systems designed to remove particulate matter only is designed to comprise 30 percent solids.

[h]Weight based on 50 percent solids. Sludge from systems using an SO_2 wet scrubber or a combined SO_2-PM wet scrubber is designed to comprise 50 percent solids.

[i]Includes desulfurization products from dry scrubber.

[j]For wood-fired boilers a portion of the fly ash collected by the mechanical collector is burned by reinjection. This decreases the amount of solid waste generated.

local regulations govern the disposal practices at the landfills and pond sites. Solid wastes from spray dryers (dry scrubbing) are handled in the same manner as fly ash. Off-site landfilling has been selected as the disposal method for the first two dry scrubbing systems installed at industrial boiler sites.[5]

The main sludge disposal options for wet FGD systems include ponding and landfilling. Ponding is the simpler of the two methods, but is potentially more harmful to the environment. Ponding involves slurrying the sludge to a pond, allowing it to settle, and pumping the supernatant liquor either to a treatment process or back to the facility for reuse. Because there is always a hydraulic head on the waste in the bottom of the pond, the potential for leachates reaching ground water sources beneath the pond is greater than for a landfill. Use of the pond area may be limited after disposal ceases, mainly because of the poor load bearing capabilities of the sludge compared to the original soil structure.[6]

Landfill disposal of FGD wastes in a specially prepared site requires some processing of the wet scrubber sludge (either stabilization or fixation) to obtain a soil-like material that may be loaded, transported, and placed as fill. Stabilization refers to the addition of fly ash or other similar material to the sludge to produce only physical changes without any chemical reactions. Fixation is a type of stabilization which involves the addition of reagents (such as lime) to cause chemical reactions with the sludge.[7] The objective of these treatment methods is to increase the load bearing capacity of the raw sludge and to decrease the permeability of the sludge, and correspondingly, the mass transport rate of contaminants leaching out of the sludge.[8]

Proper design of both ponds and landfills is required to assure minimal environmental impact of solid waste disposal. Contaminants that are contained in ponds and landfills or accidentally spilled on the surface can enter ground-water systems as a result of two processes: leakage and leaching. As the term implies, leakage refers to migration to the subsurface of fluids that are deposited on the surface. Leakage is of more concern for ponds and spills than landfills. Leaching, on the other hand, denotes the introduction of water (usually infiltrating precipitation) into the waste after it has been landfilled so that contaminants are dissolved and elutriated or leached out of the solid material.

Transport of trace elements and other potential pollutants from the disposal site via leaching or run off is determined by many factors, including: (1) the chemical form and concentration of the potential pollutant in the waste, (2) the permeability, sorption capacity, and porosity of the substrate, (3) soil and leachate pH, (4) the permeability and porosity of the waste, (5) the proximity of the disposal site to the ground-water table and/or surface water, (6) the presence or absence of clay or plastic liners or other methods of enclosing the wastes in materials of low permeability, and (7) climatic factors such as precipitation, temperature, and relative humidity.[9] However, if a landfill site is properly designed and operated, these leaching and runoff problems can be averted and the landfill area eventually reused either for recreational or building use purposes.[10]

7.3.3 Waste Disposal Regulations

At the present time the federal regulations governing solid waste disposal are not fully defined. EPA recently (May 2, 1980) issued Phase I final Resource Conservation and Recovery Act (RCRA) regulations covering the framework for management of solid wastes. In addition, Congress is currently considering legislation that would exempt certain "special wastes" (as defined in the proposed regulations) from the possibility of being classified as hazardous until more data are gathered about their characteristics.[11]

The Phase I RCRA regulations exempt fly ash, bottom ash, slag, and air pollutant emission control sludge produced in the combustion of fossil fuels from consideration as hazardous wastes. This exemption also applies to industrial boiler FGD sludges.[11]

Non-hazardous waste disposal management and techniques will be governed by Section 4004 of RCRA. This section requires states to implement disposal programs that will protect the environment (especially ground water) from contamination. EPA has also published Landfill Disposal of Solid Waste, Proposed Guidelines that will act as a guide to the states as to what their disposal management programs should contain.[12]

Disposal of non-hazardous wastes will require at a minimum that a clay liner be used at the disposal site, that the waste be covered at the end of each operating day, that access to the site be controlled, that ground-water quality at the site boundary be monitored, and that a final impermeable cover be placed and revegetation occur.[12] These activities are required, primarily, to protect ground water in the disposal area.

7.3.4 National Solid Waste Impact

Table 7-10 shows the national solid waste impacts in 1990 of applying Baseline and Control Levels I and II to boilers affected by a potential NSPS. As was done in Section 7.1.1 for the national air impact analysis, this analysis is of the solid waste impacts resulting from nonfossil fuel firing only. Any associated impacts resulting from the firing of fossil fuels are not included. The amounts of solid waste are on a dry basis because the specific types of control devices which might be used could not be determined. The amounts of dry solid waste generated at the Baseline Control Level and Control Levels I and II are shown. The emission level used to calculate the national solid waste impact of the Baseline Control Level is the average of existing State emission regulations shown in Chapter 3. The increase of dry solid waste from emission control alone above the baseline control for Control Level II ranges from approximately 2 percent for RDF to 10 percent for wood. The increase in total solid waste generated by the boiler, including the boiler bottom ash and solid waste generated by emission controls, shows a range of increase of less than one percent for MSW up to 7 percent for wood.

Table 7-10 also shows the annual nonfossil fuel consumption rates which will be achieved by the end of 1990 by boilers affected by a potential NSPS. This fuel usage represents a positive national solid waste impact because if the fuel was not burned it would have to be disposed of. As shown in the table this benefit is reduced only slightly by the solid waste increase due to air pollution control requirements for the various control levels.

TABLE 7-10. NATIONAL SOLID WASTE IMPACT OF BASELINE AND CONTROL LEVELS I AND II IN 1990

Year	Fuel[c]	Annual Amount of[a,b] Nonfossil Fuel Fired in NFFBs Gg/yr(10^{3}tons/yr)	Annual Amount of Boiler Bottom Ash Produced Gg/yr(10^{3}tons/yr)	Annual Amounts of Solid Waste[i] Generated Due to Emission Control Gg/yr(10^{3}tons/yr)			Annual Reduction of Solid Waste Achieved by Firing Nonfossil Fuels Gg/yr(10^{3}tons/yr)		
				Baseline[j]	Level I	Level II	Baseline	Level I	Level II
	Wood[d]	24,300 (26,800)	164 (181)	310 (342)	330 (364)	341 (376)	23,900 (26,300)	23,900 (26,300)	23,800 (26,200)
	MSW[e]	4,250 (4,680)	1,060 (1,170)	66.0 (72.8)	67.5 (74.4)	68.5 (75.5)	3,120 (3,440)	3,120 (3,440)	3,110 (3,430)
1990	MSW,ISW[f]	1,670 (1,840)	500 (552)	0	1.49 (1.64)	2.48 (2.73)	1,170 (1,290)	1,170 (1,290)	1,170 (1,290)
	RDF[g]	3,770 (4,160)	607 (669)	123 (136)	125 (138)	126 (139)	3,050 (3,360)	3,040 (3,350)	3,040 (3,350)
	Bagasse	4,350 (4,790)	27.1 (29.9)	75.2 (82.9)	82.4 (90.8)	h	4,250 (4,680)	4,240 (4,670)	h

[a]Includes only NFFBs affected by potential New Source Performance Standards (NSPS). This will be the NFFBs installed in 1984 through 1990.

[b]Based on the population of NFFBs affected by NSPS, their hourly fuel feed rates, and annual capacity factors of 0.45 for bagasse and 0.60 for all other NFFBs.

[c]Wood - all types of wood fuels.
MSW - municipal solid waste.
RDF - refuse derived fuel.
ISW - industrial solid waste

[d]The high ash bark and salt-laden wood fuel were evaluated as model boiler cases to determine the sensitivity of emission control costs for wood-fired boilers to the ash and salt contents of wood fuels. For calculating national environmental impacts of wood-fired boilers the wood fuel category is used to represent boiler burning all types of wood fuels.

[e]Includes all MSW-fired boilers except small modular units.

[f]Includes only small modular MSW-fired boilers and ISW-fired boilers.

[g]Assuming RDF supplies 100 percent of the boiler heat input. For boilers firing 100 percent RDF the baseline control level is the same as the baseline level for a similar size MSW-fired boiler.

[h]A second control level is not being evaluated for bagasse-fired boilers.

[i]Dry basis.

[j]For calculating national impacts the Baseline Control Level is the average of existing State regulations shown in Chapter 3.

7.4 ENERGY IMPACT OF CONTROL TECHNOLOGIES

All of the alternative control systems installed for PM and SO_2 emission control require electrical energy. Major electrical energy consumers are the fans required to overcome the pressure drop across the control systems. For ESPs energy is also required to create the corona discharge and to run auxiliary equipment such as collection plate rappers.[13] Lesser amounts of electrical energy are needed for motors that operate the pumps in wet scrubbing systems and bag cleaning mechanisms in fabric filters.

Table 7-8 shows the energy demand of the control devices associated with each model boiler. The energy demand is expressed in both kilowatts and in thermal megawatts of heat input to the power boiler supplying the electrical energy. Energy requirements for the systems with a MC upstream of a secondary control device, such as a WS or ESP, were calculated based on energy usage of both devices. Also included was the energy usage of associated operations such as slurry pumping and sludge handling. The significant result of these calculations, shown in Table 7-11, is that the model boiler control system energy requirements associated with each of the control levels varies from less than one percent to 3.4 percent of the heat input to the model boilers.

Table 7-11 shows predicted quantities of nonfossil fuels which will be burned in 1990 in boilers affected by potential New Source Performance Standards. For example, this table shows that by the end of 1990 nonfossil fuel will be burned at the rate of 420 PJ/yr (398 x 10^{12} Btu/yr) in these boilers. However, the electrical demands of the emission controls lead to increased fossil fuel use at the utility power boiler (see Table 7-8). This increase in fossil fuel at the power boiler is shown in Table 7-11 as a percentage of the heating input of nonfossil fuel consumed by the NFFBs being controlled. The percentages expressed show the range of energy demands for the various types of control systems considered at each control level.

TABLE 7-11. NATIONAL ENERGY IMPACTS OF NFFB EMISSION CONTROL SYSTEMS FOR BASELINE CONTROL AND CONTROL LEVELS I AND II IN 1990

Year	Fuel[b]	Annual Energy Input[a] To NFFBs PJ/yr (10^{12} Btu/yr)	Control System Energy Demands Expressed As a Percent of the Amount Heat Input to NFFBs		
			Baseline	Control Level I	Control Level II
	Wood[c]	258 (245)	0.6 - 1.8[j]	2.09 - 2.17[g]	1.31 - 3.40[g]
	MSW[d]	48.1 (45.6)	0.70	0.85	1.17
1990	MSW,ISW[e]	23.1 (21.9)	0	2.80	1.10
	RDF[f]	50.9 (48.2)	h	h	h
	Bagasse	39.6 (37.5)	0.68	0.92	i
	Total	420 (398)			

[a] Includes only NFFBs controlled by potential New Source Performance Standards.

[b] Wood - all types of wood fuels.
MSW - municipal solid waste
RDF - refuse derived fuel
ISW - industrial solid waste

[c] The high ash bark and salt-laden wood fuels were evaluated as model boiler cases to determine the sensitivity of emissions control costs for wood-fired boilers to the ash and salt contents of wood fuels. For calculating national environmental impacts of wood-fired boilers the wood fuel category is used to represent boilers burning all types of wood fuels.

[d] Includes all MSW-fired boilers except small modular units.

[e] Includes only small modular MSW-fired boilers and ISW-fired boilers.

[f] Based on RDF supplying 100 percent of the boiler heat input.

[g] Values shown represent the range of energy demands based on the different types of control systems considered for each level (example: ESP, WS, FF)

[h] The energy demands of control systems for 100% firing of RDF are not known since a model boiler was not evaluated for this case. However, they are similar to those shown for large MSW-fired boilers.

[i] A second control level is not being evaluated for bagasse-fired boilers.

[j] Values shown represent the range of energy demands of the different types of control systems commonly used to meet existing State regulations.

7.5 OTHER IMPACTS

An increase in noise at the industrial boiler site is expected as a result of the operation of the various control techniques but the increase is expected to be small compared to background noise levels. For FGD systems the higher level of noise would result from fans, pumps, and agitators. For ESPs, the higher noise levels are due to the fans, pumps, compressors, electrode rappers, etc. For FFs, the bag cleaning mechanisms result in increased noise levels. However, equipment which emit high noise levels will be used at industrial sites regardless of any NSPS. Therefore this standard is not expected to cause a significant increase in total noise levels.

7.6 OTHER ENVIRONMENTAL CONCERNS

7.6.1 Long-Term Gains/Losses

Increased emission control of the air pollutants resulting from the operation of nonfossil and combination fuel fired boilers would result in reduced air emissions and increased energy, water (if sodium scrubbing systems are used), and solid waste impacts. The solid waste impact would be mitigated by other EPA regulatory programs. The long-term gains achieved would result from reducing PM and SO_2 emissions to the ambient air. Another important long-term benefit would be the application of control technology which makes possible the use of nonfossil fuels in an environmentally acceptable manner. The use of these fuels will serve to reduce the use of non-renewable fossil fuels for steam generation.

7.6.2 Environmental Impact of Delayed Standard

As analyzed in Section 7.1, there are significant air quality benefits achieved by emission reductions at control levels I and II compared to baseline emissions. Large quantities of pollutants are reduced and incremental ambient air quality benefits are achieved. Therefore, the impact of a delayed standard would be a negative one since the incremental benefit discussed in Section 7.1 would not be achieved as long as the standard was delayed.

7.7 REFERENCES

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6. Duvel, W.A., et al. FGD Sludge Disposal Manual. Publication No. FP-977. Palo Alto, Electric Power Research Institute, January 1979. pp. 5-1 to 5-5.

7. Reference 6, p. 2-21.

8. Reference 6, pp. 5-5 to 5-7.

9. Reference 6, pp. 7-19 to 7-29.

10. Reference 6, pp. 8-128 to 8-133.

11. Telecon. McCloskey, M., Radian Corporation, with Corson, A., EPA: Washington, D.C. May 14, 1980. Information about new RCRA regulations.

12. U.S. Environmental Protection Agency. Landfill Disposal of Solid Waste; Proposed Guidelines. Federal Register. 44(59): 18138-18148. March 26, 1979.

13. Roeck, D.R. and R. Dennis. (GCA Corporation.) Technology Assessment Report for Industrial Boiler Applications: Particulate Control. (Prepared for U.S. Environmental Protection Agency.) Research Triangle Park, N.C. Publication No. EPA-600/7-79-178h. December 1979. p. 207.

8. COSTS

In Chapter 8 is an analysis of the costs of alternative emission control techniques potentially applied to nonfossil fuel fired boilers. This analysis is organized into two major sections. Section 8.1 presents the costs of alternative emission control techniques applied in the "model" NFFBs that are developed in Chapter 6. Other costs that need to be considered during the development of NSPS, such as costs already incurred by NFFB operators to comply with existing wastewater and solid waste regulations, are discussed in Section 8.2. The costs presented in this chapter are subsequently used in Chapter 9 to assess the economic impacts of alternative emission control measures on NFFB users.

8.1 COST ANALYSIS OF MODEL BOILERS

The analysis of model boiler costs is presented in four sections. Section 8.1.1 provides background information for the cost analysis. Section 8.1.2 presents the costs for new boiler/emission control systems. Section 8.1.3 discusses factors affecting the costs of modified or reconstructed facilities. Section 8.1.4 presents the national cost impacts of alternative NFFB emission control requirements.

8.1.1 Background Information

Capital and operating estimates were developed for the various model NFFBs presented in Chapter 6. The general approach used in developing these costs consisted of several main steps. First, a series of material and energy balance calculations were performed to establish flue gas flow rates and PM and SO_2 emission rates for each boiler/emission control system. Second, emission data and associated control system design and operating data were obtained on a number of operating NFFB facilities around the country. Third, various equipment sizes and operating parameters were developed based on results of the material and energy balances and an evaluation of the emission and control system data. Finally, capital cost estimates were prepared by contacting boiler owners and process equipment vendors for price quotations in the applicable equipment size ranges and by reference to various literature cost sources. Operating costs were developed based on the material and energy balance calculations and the developed control system operating parameters.

8.1.1.1 Summary of Model Boilers. Tables 8-1 and 8-2 summarize the model boilers and emission control levels analyzed in this document. Chapter 6 contains the rationale for selecting model boiler sizes, types, fuels, emission control techniques, and emission control levels.

The selected model boilers emphasize the firing of wood fuels since nearly three-fifths of the new NFFB capacity potentially affected by NSPS will be fired with wood. The model wood-fired boilers are used to analyze the firing of three different types of wood and three potential wood/coal cofiring arrangements. Four different capacities ranging from 8.8 to 117 MW (30 to 400 x 10^6 Btu/hr) on a thermal input basis are represented by model wood-fired boilers.

The model boilers are also used to analyze the firing of two types of GSW fuels: MSW and RDF. Model boilers for MSW firing represent two different boiler types and a range of boiler capacity of 2.9 to 117 MW (10 to 400 x 10^6 Btu/hr) on a thermal input basis. Model boilers for RDF firing analyze one potential RDF/coal cofiring arrangement and capacity.

Model boilers firing bagasse represent the most typical capacity and boiler type of new bagasse-fired boilers.

The model boilers are used to analyze the impacts of three different levels of emission control. The baseline control level is the highest level of emissions expected based on the present mix of State and Federal Regulations. The second control level, Control Level I, is a more stringent level of control that is widely demonstrated in existing NFFB facilities. Control Level II, the most stringent control level analyzed, represents a level of control demonstrated in only a few existing NFFB facilities.

The model boilers are used to analyze the control of both PM and SO_2 emissions. The control of PM emissions is accomplished with mechanical collectors, wet scrubbers, electrostatic precipitators, fabric filters, or

TABLE 8-1. MODEL BOILERS

Model Boiler Number	Boiler Capacity (Thermal Input Basis)	Fuel[a]	Control Level[b] PM	Control Level[b] SO_2	Emission Control System[c] PM	Emission Control System[c] SO_2
1a	8.8 MW	Wood	B	B	MC	-
1b	(30×10^6 Btu/hr)		I	B	MC,WS	-
1c			II	B	MC,WS	
1d			II	B	MW,FF	-
1e			II	B	MC,ESP	-
2a	22.0 MW	Wood	B	B	MC	-
2b	(75×10^6 Btu/hr)		I	B	MC,WS	-
2c			II	B	MC,WS	-
2d			II	B	MC,FF	-
2e			II	B	MC,ESP	-
2f			II	B	MC,EGB	-
3a	44.0 MW	Wood	B	B	MC	
3b	(150×10^6 Btu/hr)		I	B	MC,WS	-
3c			II	B	MC,WS	
3d			II	B	MC,FF	-
3e			II	B	MC,ESP	
3f			II	B	MC,EGB	-
4a	117 MW	Wood	B	B	MC	-
4b	(400×10^6 Btu/hr)		I	B	MC,WS	-
4c			II	B	MC,WS	-
4d			II	B	MC,FF	-
4e			II	B	MC,ESP	-
4f			II	B	MC,EGB	-
5a	44.0 MW	HAB	B	B	MC,WS	-
5b	(150×10^6 Btu/hr)		I	B	MC,WS	-
5c			II	B	MC,FF	-
6a	44.0 MW	SLW	B	B	MC,WS	-
6b	(150×10^6 Btu/hr)		I	B	MC,WS	-
6c			II	B	MC,FF	-
7a	44.0 MW	75% Wood/[d]	B	B	MC,WS	-
7b	(150×10^6 Btu/hr)	25% HSE	I	B	MC,WS	-
7c			I	I	MC,FGD-WS	FGD-WS
7d			II	B	MC,ESP	-
7e			II	B	MC,FF	-
7f			II	I	MC,FF	FGD-DS
7g			II	II	MC,ESP	FGD-WS
8a	44.0 MW	50% Wood/[d]	B	B	MC,FGD-WS	FGD-WS
8b	(150×10^6 Btu/hr)	50% HSE	I	B	MC,FGD-WS	FGD-WS
8c			I	I	MC,FGD-WS	FGD-WS
8d			I	II	MC,FGD-WS	FGD-WS
8e			II	B	MC,FF	FGD-DS[e]
8f			II	I	MC,FF	FGD-DS
8g			II	II	MC,ESP	FGD-WS

See footnotes at end of table.

TABLE 8-1. (CONTINUED)

Model Boiler Number	Boiler Capacity (Thermal Input Basis)	Fuel[a]	Control Level[b] PM	Control Level[b] SO_2	Emission Control System[c] PM	Emission Control System[c] SO_2
9a	117 MW	50% Wood/[d]	B	B	MC,FGD-WS	FGD-WS
9b	(400 x 10^6 Btu/hr)	50% HSE	I	I	MC,FGD-WS	FGD-WS
9c			II	I	MC,FF	FGD-DS
9d			II	II	MC,ESP	FGD-WS
10a	44.0 MW	50% Wood/[d]	B	B	MC,WS	-
10b	(150 x 10^6 Btu/hr)	50% LSW	I	B	MC,WS	-
10c			I	I	MC,FGD-WS	FGD-WS
10d			I	II	MC,FGD-WS	FGD-WS
10e			II	B	MC,FF	-
10f			II	B	MC,ESP	-
10g			II	I	MC,FF	FGD-DS
10h			II	II	MC,ESP	FGD-WS
11a	44.0 MW	50% RDF/[d]	B	B	FGD-WS	FGD-WS
11b	(150 x 10^6 Btu/hr)	50% HSE	I	I	FGD-WS	FGD-WS
11c			I	II	FGD-WS	FGD-WS
11d			II	I	ESP	FGD-WS
11e			II	II	ESP	FGD-WS
12a	2.9 MW	MSW	B	B	-	-
12b	(10 x 10^6 Btu/hr)		I	B	WS	-
12c			II	B	FF	-
13a	44.0 MW	MSW	B	B	ESP	-
13b	(150 x 10^6 Btu/hr)		I	B	ESP	-
13c			II	B	ESP	-
14a	117 MW	MSW	B	B	ESP	-
14b	(400 x 10^6 Btu/hr)		I	B	ESP	-
14c			II	B	ESP	-
15a	58.6 MW	Bagasse	B	B	MC	-
15b	(200 x 10^6 Btu/hr)		I	B	WS	-

[a]Wood - hog fuel (wood/bark mixture)
HAB - high ash bark
SLW - salt-laden wood
HSE - high sulfur eastern coal
LSW - low sulfur western coal
RDF - refuse derived fuel
MSW - municipal solid waste

[b]B refers to Baseline Control level.
I refers to Control Level I.
II refers to Control Level II.

[c]MC - mechanical collector
WS - wet scrubber
FF - fabric filter
ESP - electrostatic precipitator
EGB - electrostatic gravel bed filter
FGD-WS - flue gas desulfurization; double alkali or lime wet scrubber
FGD-DS - flue gas desulfurization; lime dry scrubber
Control systems separated by a comma mean that both are used at the same time, not that either may be used independently. Mechanical collectors are included for fly ash reinjection on all of the boilers firing wood.

[d]Average fuel mixture on a heat input basis.

[e]Only a portion of the flue gas is scrubbed.

TABLE 8-2. EMISSION LEVELS FOR THE MODEL BOILERS

Model Boiler Number	Fuel[a]	Standard Boiler MW (10^6 Btu/hr)	Uncontrolled Emissions ng/J (lb/10^6 Btu) PM-BMC[c]	PM-AMC[c]	SO_2[g]	Baseline Control Level[d] ng/J (lb/10^6 Btu) PM	SO_2	Control Level I ng/J (lb/10^6 Btu) PM	SO_2[e]	Control Level II ng/J (lb/10^6 Btu) PM	SO_2[f]
1	Wood	8.8 (30)	2100 (4.88)	418 (0.973)	-	258 (0.6)	- -	64.5 (0.15)	-	21.5 (0.05)	- -
2	Wood	22.0 (75)	2100 (4.88)	418 (0.973)		258 (0.6)		64.5 (0.15)		21.5 (0.05)	
3	Wood	44.0[i] (150)	2100 (4.88)	418 (0.973)	-	258 (0.6)		64.5 (0.15)	-	21.5 (0.05)	-
4	Wood	117 (400)	2100 (4.88)	418 (0.973)	-	258 (0.6)		64.5 (0.15)	-	21.5 (0.05)	
5	HAB	44.0 (150)	2950 (6.87)	593 (1.38)		146 (0.34)	-	64.5 (0.15)		21.5 (0.05)	
6	SLW	44.0 (150)	2590 (6.03)	899 (2.09)	-	146 (0.34)	- -	64.5 (0.15)	-	21.5 (0.05)	
7	75% Wood/[b] 25% HSE	44.0 (150)	2200 (5.11)	440 (1.02)	641 (1.49)	138 (0.32)	641 (1.49)	64.5 (0.15)	194 (0.45)	21.5 (0.05)	64.5 (0.15)
8	50% Wood/[b] 50% HSE	44.0 (150)	2300 (5.35)	460 (1.07)	1240 (2.89)	138 (0.32)	1075 (2.50)	64.5 (0.15)	374 (0.87)	21.5 (0.05)	125 (0.29)
9	50% Wood/[b] 50% HSE	117 (400)	2300 (5.35)	460 (1.07)	1240 (2.89)	43.0 (0.10)	516 (1.2)	43.0 (0.10)	374 (0.87)	21.5 (0.05)	125 (0.29)
10	50% Wood/[b] 50% LSW	44.0 (150)	1840 (4.27)	367 (0.853)	275 (0.639)	138 (0.32)	275 (0.639)	64.5 (0.15)	81.7 (0.19)	21.5 (0.05)	27.5 (0.06)
11	50% RDF/[b] 50% HSE	44.0 (150)	2500 (5.82)	- -	1350 (3.15)	138 (0.32)	1075 (2.50)	64.5 (0.15)	405 (0.94)	21.5 (0.05)	135 (0.31)
12	MSW	2.9 (10)	129 (0.30)	- -	212 (0.49)	129 (0.30)	212 (0.49)	64.5 (0.15)	212 (0.49)	21.5 (0.05)	212 (0.49)
13	MSW	44.0[i] (150)	1440 (3.36)	- -	212 (0.49)	73.1 (0.17)	212 (0.49)	43.0 (0.10)	212 (0.49)	21.5 (0.05)	212 (0.49)
14	MSW	117 (400)	1440 (3.36)	- -	212 (0.49)	73.1 (0.17)	212 (0.49)	43.0 (0.10)	212 (0.49)	21.5 (0.05)	212 (0.49)
15	Bagasse	58.6 (200)	2170 (5.05)	- -	- -	267 (0.62)	- -	86.0 (0.20)	- -	-[h] -	- -

See footnotes on second page.

FOOTNOTES TO TABLE 8-2.

[a]Wood - hog fuel (wood/bark mixture)
HAB - high ash bark
SLW - salt-laden wood
RDF - refuse derived fuel
MSW - municipal solid waste
HSE - high sulfur eastern coal
LSW - low sulfur western coal

[b]Average fuel mixture on a heat input basis.

[c]BMC - before mechanical collector or any other control equipment.
AMC - after mechanical collector when the mechanical collector is not the final control device.
Both values are included only for cases with fly ash reinjection.

[d]Emission level equivalent to the uncontrolled emission rate, or to the highest emission rate expected under the current mix of State and Federal Regulations. For model boilers 1-4 the level also represents emissions after the mechnical collector when the mechanical collector is the final control device.

[e]The emission level shown represents a 70 percent reduction from uncontrolled SO_2 emissions for the combination fuel boilers and no control for the others.

[f]The emission level shown represents a 90 percent reduction from uncontrolled SO_2 emissions for the combination fuel boilers and no control for the others.

[g]SO_2 emissions for boilers firing bagasse of 100 percent wood are low and have not been quantified for this analysis.

[h]A level more stringent than Control Level I was not evaluated.

electrostatic gravel-bed filters. Control of SO_2 emissions is analyzed only for model boilers cofiring nonfossil and fossil fuels and is accomplished with either wet scrubbing or dry scrubbing techniques.

8.1.1.2 Model Boiler Design Specifications. Boiler design and fuel specifications are summarized in Tables 8-3 and 8-4. These specifications are discussed in Chapter 6.

Emission control system design specifications are detailed in Table 8-5. These specifications are mainly based on emission test data and design data from existing NFFB facilities. Specifications for wet scrubbers applied to RDF/coal cofired and MSW-fired boilers are based on conceptual analyses since no scrubber emission test data are available for these applications.[1,29]

8.1.1.3 Cost Estimating Sources. Equipment costs and operating costs for the model boilers specified in Tables 8-3, 8-4, and 8-5 are estimated from the sources listed in Table 8-6. Equipment costs estimated from these sources are preliminary or budget authorization estimates developed in terms of mid-1978 dollars and generally accurate to ±30 percent.

8.1.1.4 Capital Cost Bases. The capital cost is the total investment required to supply a complete boiler/emission control system. Components of the capital costs, itemized in Table 8-7, include total direct and indirect investment costs, contingencies, land, and working capital.

The equipment costs determined from the sources listed in Table 8-6 are the basis of the other capital cost components listed in Table 8-7. The cost of equipment installation, for example, is estimated as a fraction of the equipment cost. Other cost components such as engineering are then estimated as fractions of the sum of the equipment and installation costs.[1]

The capital costs include the following boiler equipment items:

- fuel handling and storage systems,
- feedwater and condensate treatment systems,
- boiler and auxiliaries (feed pumps, chemical feed system, soot blowers, instrumentation, and FD and ID fans), and
- bottom ash disposal systems

TABLE 8-3. MODEL BOILER DESIGN SPECIFICATIONS

Model Boiler Number	1	2	3	4	5
Thermal input, MW (10^6 Btu/hr)	8.8(30)	22.0(75)	44.0(150)	117(400)	44.0(150)
Fuel[a]	Wood	Wood	Wood	Wood	HAB
Fuel rate, kg/s (ton/hr)	0.829 (3.29)	2.07 (8.22)	4.15 (16.4)	11.1 (43.9)	4.32 (17.2)
Analysis					
% sulfur	0.02	0.02	0.02	0.02	0.02
% ash	1.00	1.00	1.00	1.00	3.00
Heating value, kJ/kg (Btu/lb)	10,600 (4,560)	10,600 (4,560)	10,600 (4,560)	10,600 (4,560)	10,160 (4,370)
Excess air, %	50	50	50	50	50
Flue gas flow rate, m^3/s (acfm)	6.94(14,700)	17.3(36,700)	34.7(73,500)	92.5(196,000)	34.7(73,500)
Flue gas temperature, °K(°F)	478(400)	478(400)	478(400)	478(400)	478(400)
Load factor, %	60	60	60	60	60
Flue gas constituents,[b] kg/hr(lb/hr)					
Fly ash (before mechanical collector)[c]	66.2(146)	166(366)	332(732)	885(1950)	467(1030)
Fly ash (after mechanical collector)[h]	13.3(29.3)	33.2(73.2)	66.4(146)	177(390)	93.9(207)
SO_2	—	—	—	—	—
NO_x	3.40(7.50)	8.53(18.8)	17.0(37.5)	45.3(100)	17.0(37.5)
Ash from sand classifier,[i] kg/hr(lb/hr)	29.2(64.4)	73.0(161)	146(322)	390(859)	255(563)
Bottom ash, kg/hr(lb/hr)	20.1(44.4)[j]	50.3(111)[j]	101(222)[j]	269(592)[j]	292(644)
Boiler Output, MW (10^6 Btu/hr)					
Steam	5.7(19.5)	14.3(48.7)	28.6(97.5)	76.1(260)	28.6(97.5)
Losses	3.1(10.5)	7.7(26.3)	15.4(52.5)	41.0(140)	15.4(52.5)
Efficiency, %	65	65	65	65	65
Steam quality					
Pressure,[d] kPa(psig)	1,720(250)	1,720(250)	1,720(250)	5,170(750)	1,720(250)
Temperature, °K (°F)	481(406)	481(406)	481(406)	672(750)	481(406)
Steam production,[e] kg/hr(lb/hr)	8,890(19,600)	22,200(49,000)	44,500(98,200)	101,000(223,000)	44,500(98,200)

See footnotes at end of table.

TABLE 8-3. (CONTINUED)

Model Boiler Number	6	7	8	9	10
Thermal input, MW(10^6 Btu/hr)	44.0(150)	44.0(150)	44.0(150)	117(400)	44.0(150)
Fuel[a]	SLW	75% Wood/[f,g] 25% HSE	50% Wood/[f,g] 50% HSE	50% Wood/[f,g] 50% HSE	50% Wood/[f,g] 50% LSW
Fuel rate, kg/s (ton/hr)	4.18 (16.6)	3.11/0.401 (12.3/1.59)	2.07/0.801 (8.22/3.18)	5.52/2.13 (21.9/8.47)	2.07/0.985 (8.22/3.91)
Analysis					
% sulfur	0.02	0.02/3.54	0.02/3.54	0.02/3.54	0.02/0.60
% ash	1.49	1.00/10.58	1.00/10.58	1.00/10.58	1.00/5.40
Heating value, kJ/kg (Btu/lb)	10,490 (4510)	10,600/27,440 (4,560/11,800)	10,600/27,440 (4,560/11,800)	10,600/27,440 (4,560/11,800)	10,600/22,330 (4,560/9,600)
Excess air, %	50	50	50	50	50
Flue gas flow rate, m^3/s (acfm)	34.7(73,500)	33.3(71,300)	32.4(69,200)	87.1(184,500)	33.1(70,200)
Flue gas temperature, °K(°F)	478(400)	478(400)	478(400)	478(400)	478(400)
Load factor, %	60	60	60	60	60
Flue gas constituents,[b] kg/hr(lb/hr)					
Fly ash (before mechanical collector)[c]	411(905)	348(767)	364(803)	971(2140)	290(640)
(after mechanical collector)[h]	142(314)	69.6(153)	72.8(160)	194(428)	58(128)
SO_2	—	102(224)	197(434)	526(1160)	43.5(95.8)
NO_x	17.0(37.5)	23.5(51.7)	29.9(66.0)	79.7(176)	29.9(66.0)
Ash from sand classifier,[i] kg/hr(lb/hr)	147(325)	189(416)	231(510)	617(1360)	172(380)
Bottom ash, kg/hr(lb/hr)	101(222)	129(285)	157(348)	421(928)	117(259)
Boiler Output, MW (10^6 Btu/hr)					
Steam	28.6(97.5)	30.4(104)	32.1(110)	85.4(292)	32.1(110)
Losses	15.4(52.5)	13.6(46)	11.9(40)	31.6(108)	11.9(40)
Efficiency, %	65	69	73	73	73
Steam quality					
Pressure,[d] kPa(psig)	1,720(250)	1,720(250)	1,720(250)	5,170(750)	1,720(250)
Temperature, °K(°F)	481(406)	481(406)	481(406)	672(750)	481(406)
Steam production,[e] kg/hr(lb/hr)	44,500(98,200)	47,600(105,000)	50,300(111,000)	114,000(251,000)	50,300(111,000)

See footnotes at end of table.

TABLE 8-3. (CONTINUED)

Model Boiler Number	11	12	13	14	15
Thermal input, MW(10^6 Btu/hr)	44.0(150)	2.9(10)	44.0(150)	117(400)	58.6(200)
Fuel[a]	50% RDF/[f,g] 50% HSE	MSW	MSW	MSW	Bagasse
Fuel rate, kg/s (ton/hr)	1.63/0.801 (6.48/3.18)	0.260 (1.03)	3.88 (15.4)	10.3 (41.0)	6.43 (25.5)
Analysis					
% sulfur	0.17/3.54	0.12	0.12	0.12	Trace
% ash	19.44/10.58	22.38	22.38	22.38	1.10
Heating value, kJ/kg (Btu/lb)	13,460/27,440 (5,790/11,800)	11,340 (4,875)	11,340 (4,875)	11,340 (4,875)	9,116 (3,920)
Excess air, %	50	100	100	100	50
Flue gas flow rate, m^3/s(acfm)	31.8(67,300)	2.79(5,920)	41.8(88,500)	111(236,000)	47.7(101,000)
Flue gas temperature, °K(°F)	478(400)	478(400)	478(400)	478(400)	478(400)
Load factor, %	60	60	60	60	45
Flue gas constituents,[b] kg/hr(lb/hr)					
Fly ash (before mechanical collector)[c]	396(873)	1.36(3.00)	229(504)	608(1340)	458(1,010)
(after mechanical collector)[h]	-	-	-	-	-
SO_2	214(472)	2.23(4.92)	33.5(73.8)	89.3(197)	-
NO_x	38.6(85.0)	1.40(3.08)	21.0(46.2)	56.0(123)	18.1(40.0)
Ash from sand classifier,[i] kg/hr(lb/hr)	-	-	-	-	-
Bottom ash, kg/hr(lb/hr)	1,050(2,320)	279(615)	3,490(7,690)	9,310(20,500)	145(319)
Boiler Output, MW (10^6 Btu/hr)					
Steam	33.4(114)	1.6(5.5)	30.8(105)	81.9(280)	35.2(120)
Losses	10.6(36)	1.3(4.5)	13.2(45)	35.1(120)	23.4(80)
Efficiency, %	76	55	70	70	60
Steam quality					
Pressure,[d] kPa(psig)	3,100(450)	1,720(250)	3,100(450)	5,170(750)	1,720(250)
Temperature, °K(°F)	589(600)	481(406)	589(600)	672(750)	533(500)
Steam production,[e] kg/hr(lb/hr)	47,200(104,000)	2,510(5,540)	43,600(96,000)	109,000(241,000)	51,700(114,000)

See footnotes at end of table.

FOOTNOTES TO TABLE 8-3:

[a]Wood - hog fuel (wood/bark mixture)
HAB - high ash bark
SLW - salt-laden wood
HSE - high sulfur eastern coal
LSW - low sulfur western coal
RDF - refuse derived fuel
MSW - municipal solid waste

[b]Uncontrolled emissions.

[c]Fly ash before mechanical collector means uncontrolled emissions prior to any control device whether a mechanical collector is used or not.

[d]Guage pressure.

[e]Assuming a saturated condensate return at 10 psig.

[f]Average fuel mixture on heat input basis.

[g]Boilers cofiring wood and coal are designed to fire wood up to 100 percent of the boiler capacity. These boilers and their emission control systems are designed to fire coal only up to 30 percent or 60 percent of the boiler capacity depending on whether the average cofiring ratio is 25 percent or 50 percent. The model boiler cofiring RDF and coal is designed to fire coal up to 100 percent of capacity and RDF up to 60 percent of capacity.

[h]Fly ash after the mechanical collector is shown only for cases where fly ash reinjection is used. The value shown represents a mechanical collector used as a precleaner prior to another control device. For model boilers 1a - 4a, where the mechanical collector is the final control device, this value would be the mass equivalent of an emission level of 258 ng/J (0.6 lb/10^6 Btu).

[i]Sand classifiers are only used with systems employing fly ash reinjection (model boilers 1-10). The value shown represents the difference in the amount of fly ash collected by the mechanical collector and the amount of fly ash reinjected into the boiler furnace.

[j]These values are for cases where the mechanical collector is used as a precleaner prior to another control device. Where the mechanical collector is the final control device, these values would be 34.3, 85.7, 171, and 458 kg/hr (75.7, 189, 378, and 1009 lb/hr) for model boilers 1a, 2a, 3a, and 4a respectively.

TABLE 8-4. ULTIMATE ANALYSES OF THE FUELS SELECTED FOR THE MODEL BOILERS

Fuel[a]	Composition, % by weight							Gross Heating Value kJ/kg (Btu/lb)
	Moisture	Carbon	Hydrogen	Nitrogen	Oxygen	Sulfur	Ash	
Wood	50.00	26.95	2.85	0.08	19.10	0.02	1.00	10,600 (4,560)
HAB	50.00	25.85	2.73	0.08	18.32	0.02	3.00	10,160 (4,370)
SLW	50.00	26.68	2.82	0.08	18.91	0.02	1.49[b]	10,500 (4,510)
RDF[c]	22.42	31.30	4.62	0.61	21.44	0.17	19.44	13,460 (5,790)
MSW[c]	27.14	26.73	3.60	0.17	19.74	0.12	22.38	11,340 (4,875)
Bagasse	52.00	22.60	3.10	0.10	21.10	Trace	1.10	9,116 (3,920)
HSE	8.79	64.80	4.43	1.30	6.56	3.54	10.58	27,440 (11,800)
LSW	20.80	57.60	3.20	1.20	11.20	0.60	5.40	22,330 (9,600)

[a]Wood - hog fuel (wood/bark mixture)
HAB - high ash bark
SLW - salt-laden wood
RDF - refuse derived fuel
MSW - municipal solid waste
HSE - high sulfur eastern coal
LSW - low sulfur western coal

[b]Salt makes up 0.5 percent of the fuel composition and is included here as ash.

[c]Composition does not total 100 percent due to the presence of chlorine which is not shown here.

TABLE 8-5. EMISSION CONTROL SYSTEM DESIGN SPECIFICATIONS[1]

Control System	Item	Specification
Multiple cyclone	Material of construction	Carbon steel
	Tube diameter	23 cm (9 in.)
	Pressure drop	750 Pa (3 in. w.c.)
	Design PM removal efficiency	Model boilers 1a-4a: 88% 1b-e, 2b-f, 3b-f, 4b-f, 5, 7-10: 80% 6: 65% 15: 88%
Wet scrubbers	Material of construction	Model boilers 1-5, 12, 15: FRP-lined carbon steel 6-11: stainless steel type 316
	Scrubber type	Model boilers 1-5a, 7-8a, 10a: impingement 1-4b,c; 5b; 6a,b; 7b,c; 8b-d; 9a,b; 10b-d; 11a-c; 12b; 15b: variable-throat venturi 7f; 8e,f; 9c; 10g: spray dryer 7-8g; 9d; 10h; 11d-e: tray tower
	Liquid-to-gas ratio (L/G)	Impingement scrubbers: 0.4 dm^3 liquid/m^3 gas (3 gal/1000 acf) Venturi scrubbers: 1.3 dm^3/m^3 (10 gal/1000 acf) Spray dryers: 0.04 dm^3/m^3 (0.3 gal/1000 acf) Tray towers: 1.3 dm^3/m^3 (10 gal/1000 acf)
	Liquid discharge pressure	170 kPa (10 psig)
	Liquid pumping height	6 m (20 ft.)
	Length of piping	30 m (100 ft.)
	Sludge handling equipment/characteristics	PM removal: clarifier; sludge comprises 30% solids (except for 12b where no clarifier is used and a 10% solids slurry is produced)[2,3] SO_2 removal and combined PM/SO_2 removal: clarifier/vacuum filter; sludge comprises 50% solids[2]

TABLE 8-5. (CONTINUED)

Control System	Item	Specification
Wet scrubber	Pressure drop (gas-phase) and design PM removal efficiency	Wood-fired and wood/coal cofired boilers: Model boilers 7-8a, 10a: 1 kPa (4 in. w.c.); 60-70% 1-4b; 6a; 7b,c; 8b-d: 2.2 kPa (9 in. w.c.); 84-86% 1-4c, 6b: 5 kPa (20 in. w.c.); 93-95% 5a: 1.2 kPa (5 in. w.c.); 75% 5b: 2.7 kPa (11 in. w.c.); 89% 7-8g, 9d, 10h: 1.5 kPa (6 in. w.c.); SO_2 scrubbing only 9a,b: 3.2 kPa (13 in. w.c.); 91% 10b-d: 2 kPa (8 in. w.c.); 82% RDF/coal cofired, MSW- and bagasse-fired boilers: Model boilers 11a: 2.2 kPa (9 in. w.c.); 95% 11b-c: 3.5 kPa (14 in. w.c.); 97% 11d-e: 1.5 kPa (6 in. w.c.); SO_2 scrubbing only 12b: 3.7 kPa (15 in. w.c.); 50% 15b: 2.5 kPa (10 in. w.c.); 96%
	Design SO_2 removal efficiency	Model boilers 7c,f; 8c,f; 9b,c; 10c,g; 11b,d: 70% 7g; 8d,g; 9d; 10d,h; 11c,e: 90% 8a,b,e: 13.5% 9a: 58% 11a: 20%
	Venturi scrubber separator pressure drop	750 Pa (3 in. w.c.)
	Mist eliminator pressure drop	250-500 Pa (1-2 in. w.c.) (Mist eliminators are installed only on scrubbers with gas-phase pressure drops exceeding 1.2 kPa or 5 in. w.c.)
Fabric filter	Material of construction	Carbon steel (insulated)
	Cleaning method	Pulse-jet
	Design air-to-cloth ratio	2 cm/s (4 ft/m)
	Pressure drop	1.5 kPa (6 in. w.c.)
	Filter material	Teflon-coated glass felt
	Filter life	2 years
	Power demand	4 W/m^2 filter area (0.5 hp/1000 ft^2)
	Fire extinguishing system	Steam

TABLE 8-5. (CONTINUED)

Control System	Item	Specification
Electrostatic precipitator	Material of construction	Carbon steel (insulated)
	Design specific collection area and removal efficiency	Model boilers 1-4e; 7d,g; 8g; 9d: 65 $m^2/(m^3/s)$(330 ft^2/1000 acfm); 95.0-95.3% 10f,h: 73 $m^2/(m^3/s)$(370 ft^2/1000 acfm); 94.1% 11d,e: 52 $m^2/(m^3/s)$(265 ft^2/1000 acfm); 99.1% 13-14a: 24 $m^2/(m^3/s)$(160 ft^2/1000 acfm); 94.9% 13-14b: 47 $m^2/(m^3/s)$(240 ft^2/1000 acfm); 97.0% 13-14c: 93 $m^2/(m^3/s)$(410 ft^2/1000 acfm); 98.5%
	Pressure drop	250 Pa (1 in. w.c.)
	Power demand (average)	Model boilers 1-4e; 10f,h; 11d-e; 13a-c; 14a-c: 32 W/m^2 plate area (3 W/ft^2) 7d,g: 27 W/m^2(2.5 W/ft^2) 8g, 9d: 18 W/m^2(1.6 W/ft^2)
Electrostatic gravel-bed filter	Material of construction	Carbon steel
	Pressure drop	1 kPa (4 in. w.c.)
	Power demand	Model boiler 2f: 25 kW (33 hp) 3f: 49 kW (66 hp) 4f: 148 kW (198 hp)
Overall system	Pressure drop	250-750 Pa (1-3 in. w.c.) plus pressure drops from individual control equipment
	Duct features	Main duct length: 20-30 m (60-100 ft) Expansion joints for duct connecting two pieces of control equipment Elbows Bypass ducting (including duct, tees, elbows, dampers) for fabric filters and partial scrubbing FGD Transition ducting for ESPs

TABLE 8-6. COST ESTIMATING SOURCES[1]

Cost Item	Cost Estimating Source
Boiler Capital Costs	
Wood	Owner data
Wood/coal	Owner data and PEDCo's Final Cost Equations for Industrial Boilers[4]
RDF/coal	PEDCo's Final Cost Equations for Industrial Boilers[4]
MSW	Owner and vendor data
Bagasse	Owner data
Boiler Annual Costs	Owner and vendor data, and PEDCo's Final Cost Equations for Industrial Boilers
Emission Control Equipment Costs	
Multiple cyclone	Vendor data (Joy Manufacturing Co.)[5]
Baghouse and filter bags	Vendor data (Flex-Kleen Corp., Wheelabrator - Frye, Inc., Standard Havens Co.)[6,7,8] and GARD's Capital and Operating Costs of Selected Air Pollution Control Systems[9]
Electrostatic precipitator	PEDCo's Capital and Operating Costs of Particulate Controls on Coal- and Oil-Fired Industrial Boilers[10]
Scrubber	
- impingement	Vendor data (Joy Manufacturing Co.)[11]
- venturi	GARD's Capital and Operating Costs of Selected Air Pollution Control Systems[12]
- spray dryer and tray tower	Radian's Technology Assessment Report for Industrial Boiler Applications: Flue Gas Desulfurization[13]
- Auxiliaries (circulation pumps (2), circulation tank, piping, mixer (SO_2 scrubbing only))	Radian's Technology Assessment Report for Industrial Boiler Applications: Flue Gas Desulfurization, K.M. Guthrie's Data and Techniques for Preliminary Capital Costs Estimating, Guthrie's Process Plant Estimating, Evaluation and Control, and Peters and Timmerhaus' Plant Design and Economics for Chemical Engineers[13-16]

TABLE 8-6. (CONTINUED)

Cost Item	Cost Estimating Source
Electrostatic gravel-bed filter	Vendor data (Combustion Power Company, Inc.)[17]
Fan/Motor	GARD's Capital and Operating Costs of Selected Air Pollution Control Systems[18]
Raw material handling and regeneration (SO_2 scrubbing only) and solids separation	Radian's Technology Assessment Report for Industrial Boiler Applications: Flue Gas Desulfurization[13]
Ducting	GARD's Capital and Operating Costs of Selected Air Pollution Control Systems[19] and PEDCo's Capital and Operating Costs of Particulate Controls on Coal- and Oil-Fired Industrial Boilers[10]
Ash removal	PEDCo's Capital and Operating Costs of Particulate Controls on Coal- and Oil-Fired Industrial Boilers[10]
Screen for sand classification	Richardson Engineering Services' Rapid Construction Cost Estimating System[20]
Emission Control Annual Costs	Radian's Technology Assessment Report for Industrial Boiler Applications: Flue Gas Desulfurization, PEDCo's Capital and Operating Costs of Particulate Controls on Coal- and Oil-Fired Industrial Boilers, GARD's Capital and Operating Costs of Selected Air Pollution Control Systems, and EEA's Estimated Landfill Credit for Non-Fossil-Fueled Boilers[10,13,21,22]

TABLE 8-7. CAPITAL COST COMPONENTS

(1) DIRECT INVESTMENT COSTS

Equipment
Installation

TOTAL DIRECT INVESTMENT COSTS (TDI)

(2) INDIRECT INVESTMENT COSTS

Engineering[a]
Construction and Field Expense[b]
Construction Fees[b]
Start Up Costs[c]
Performance Tests[d]

TOTAL INDIRECT INVESTMENT COSTS (TII)

(3) CONTINGENCIES[e]

TOTAL TURNKEY COSTS (TTC)[f]

(4) Land[g]

(5) Working Capital[h]

TOTAL CAPITAL COST (Total Turnkey Costs + Land + Working Capital)

[a]Estimated as 10% of Total Direct Investment Costs (TDI) for boiler and PM control systems. For SO_2 control systems, engineering costs are the following:

(1) wet systems	up to 59 MW	(200×10^6 Btu/hr)	\$105,000
	over 59 MW	(200×10^6 Btu/hr)	\$155,000
(2) dry systems	up to 59 MW	(200×10^6 Btu/hr)	\$90,000
	over 59 MW	(200×10^6 Btu/hr)	\$160,000

For systems removing both SO_2 and PM, engineering costs are the sum of the above SO_2 control engineering costs and PM control engineering costs.

[b]Estimated as 10% of TDI.

[c]Estimated as 2% of TDI.

[d]Estimated as greater of 1% of TDI or \$3000.

[e]Estimated as 20% of the sum of TDI and TII.

[f]Sum of TDI, TII, and Contingencies.

[g]Estimated as: \$1000 for boilers with heat input capacities $\leq$22 MW (75×10^6 Btu/hr); \$2000 for boilers with heat input capacities >22 MW (75×10^6 Btu/hr); 0.084% of TTC for emission control systems.

[h]Estimated as 25% of Total Direct Operating Costs.

Note: Estimating factors are based on PEDCo's Population and Characteristics of Industrial/Commercial Boilers in the U.S. and Radian's Technology Assessment Report for Industrial Boiler Applications Flue Gas Desulfurization.[13,23]

Equipment included in the costs attributed to the emission control system include:

- control equipment and auxiliaries,
- ducting (from the boiler system to the emission control system to the stack),
- fans (increased costs for overcoming control system pressure drop),
- solids separation systems, and
- fly ash disposal systems.

In all model boilers, the bottom ash disposal system is combined with the fly ash disposal system. In allocating the capital cost of the ash disposal system, only the incremental cost of the combined system over the cost of a bottom ash disposal system is allocated to the emission control capital cost.

8.1.1.5 Annualized Cost Bases. The annualized cost includes all the costs incurred in the yearly production of steam. These costs include direct and indirect operating costs and annual charges attributed to the initial capital expenditure. Components of the annualized cost are itemized in Table 8-8.

The capital recovery factors used in this document are based on an interest rate of 10 percent and the following equipment lives:

- 20 years for small controlled-air MSW-fired boilers,
- 30 years for all other boilers,
- 15 years for scrubbing systems used for PM or SO_2 control (WS, FGD-WS, FGD-DS), and
- 20 years for all other emission control systems.

The 10 percent interest rate should not be considered as the actual cost of borrowing capital since this analysis is not intended as an economic feasibility study. Rather, 10 percent is selected as the minimum attractive rate of return to provide a basis for calculating capital charges. Different interest rates are used in the economic impact analysis presented in Chapter 9.

TABLE 8-8. ANNUALIZED COST COMPONENTS

(1) DIRECT OPERATING COSTS

Operating Labor
Supervision
Maintenance Labor
Maintenance Materials
Electricity
Chemicals
Waste Disposal
    Solids (fly ash and bottom ash)
    Sludge
Fuel

TOTAL DIRECT OPERATING COSTS

(2) INDIRECT OPERATING COSTS

Payroll Overhead[a]
Plant Overhead[b]

TOTAL INDIRECT OPERATING COSTS

(3) CAPITAL CHARGES

G & A, Taxes, and Insurance[c]
Interest on Working Capital[d]
Capital Recovery Charges[e]

TOTAL CAPITAL CHARGES

TOTAL ANNUALIZED COSTS (Direct Operating Costs + Indirect Operating Costs + Capital Charges)

[a]Estimated as 30% of the sum of Direct Labor and Supervision.

[b]Estimated as 26% of the total of Direct Labor, Supervision, Maintenance Labor, and Maintenance Materials.

[c]Estimated as 4% of the Total Capital Cost.

[d]Estimated as i% of the Working Capital where i is the interest rate.

[e]Estimated as Capital Recovery Factor (CRF) x Total Capital Cost with the CRF calculated as follows: $\mathrm{CRF} = \frac{i(1+i)^n}{(1+i)^n - 1}$ where i is the interest rate and n is the useful life of the equipment.

Utility and unit operating costs used in this document are presented in Table 8-9. The fossil fuel prices listed in this table do not include transportation costs; however, the impact of transportation costs is analyzed in Section 8.1.2. The fuel prices reflect 1978 prices in 1978 dollars.

8.1.2 New Facilities

This section presents the costs for new boiler/emission control systems. Sections 8.1.2.1 and 8.1.2.2 respectively discuss capital costs and annualized costs.

8.1.2.1 Capital Costs. Capital costs for the model boilers are summarized in Table 8-10 and are graphically portrayed in Figures 8-1, 8-2, and 8-3. The capital costs are reported both in total dollars and in dollars per unit capacity. These costs are discussed below by fuel type. The discussion emphasizes the comparison of costs for alternative control levels to costs for the baseline control level.

8.1.2.1.1 Wood-Fired Boilers. Capital costs for wood-, HAB-, or SLW-fired boilers controlled to PM Control Level I are 1.8 to 3.8 percent greater than costs for boilers controlled to the baseline level. Boilers controlled to PM Control Level II are 3.2 to 21.8 percent more costly than boilers controlled to the baseline level.

As shown in Figure 8-1, model boiler costs on a unit capacity basis decrease with system size due to boiler and emission control economies of scale.

Figure 8-2 shows that HAB-fired boilers and SLW-fired boilers are slightly more expensive than wood-fired boilers of similar sizes. Both HAB-fired and SLW-fired boilers have higher uncontrolled PM emissions than wood-fired boilers and thus require more efficient and expensive control systems. SLW-fired boilers also have greater costs because of their requirement for corrosion-resistant construction materials and high scrubber pressure drops.

Wet scrubbing systems generally have the lowest capital costs unless corrosion-resistant construction materials are required. Fabric filters have the next lowest capital costs for small boilers (<32 MW on a heat input

TABLE 8-9. UTILITY AND UNIT OPERATING COSTS, MID-1978 $ BASIS

(1) Utility Costs	
- Electricity	\$0.0258/kwh
- Water	\$0.040/m^3(\$0.15/10^3 gal)
(2) Raw Material and Labor Costs	
- Sodium carbonate	\$0.10/kg (\$ 90/ton)
- Lime	\$0.04/kg (\$ 35/ton)
- Operating labor	\$12.02/man-hour
- Supervision	\$15.63/man-hour
- Maintenance labor	\$14.63/man-hour
(3) Fuel Costs[b]	
- No.2 Distillate Oil	\$2.8/GJ (\$3/10^6Btu)
- High Sulfur Eastern Coal	\$0.70/GJ (\$0.74/10^6Btu)
- Low Sulfur Western Coal	\$0.40/GJ (\$0.42/10^6Btu)
- Refuse Derived Fuel	\$0.47/GJ (\$0.50/10^6Btu)[c]
- Other Nonfossil Fuels	no cost[d]
(4) Solid and Sludge Disposal Costs (Landfill)[e]	
- Wood-fired boilers (all sizes)	\$0.022/kg (\$20/ton)
- Wood/coal cofired boilers (44 MW or 150 x 10^6Btu/hr)	\$0.022/kg (\$20/ton)
- Wood/coal cofired boilers (117 MW or 400 x 10^6Btu/hr)	\$0.011/kg (\$10/ton)
- RDF/coal cofired boilers (44 MW or 150 x 10^6Btu/hr)	\$0.014/kg (\$12.50/ton)
- MSW-fired boilers (2.9 MW or 10 x 10^6Btu/hr)	\$0.025/kg (\$22.50/ton)
- MSW-fired boilers (44 MW or 150 x 10^6Btu/hr)	\$0.014/kg (\$12.50/ton)
- MSW-fired boilers (117 MW or 400 x 10^6Btu/hr)	\$0.010/kg (\$9/ton)
- Bagasse-fired boilers (200 x 10^6Btu/hr)	\$0.011/kg (\$10/ton)

TABLE 8-9. (CONTINUED)

(5) Credits for Not Landfilling MSW[e]	
- 2.9 MW or 10 x 10^6 Btu/hr	\$0.014/kg (\$12.50/ton)
- 44 MW or 150 x 10^6 Btu/hr	\$0.010/kg (\$9/ton)
- 117 MW or 400 x 10^6 Btu/hr	\$0.010/kg (\$9/ton)

[a]Except as noted, costs are based on PEDCo's Population and Characteristics of Industrial/Commercial Boilers in the U.S.[24]

[b]Fuel prices do not include transportation costs; the impact of transportation costs is analyzed in Section 8.1.2.

[c]The assumed RDF sale price is insufficient to cover expected production costs. The assumed RDF sale price is based on the sale price of high sulfur eastern coal, discounted at 30 percent, as discussed in Refuse-Derived Fuel and Densified Refuse-Derived Fuel.[25]

[d]For many companies nonfossil fuels may have a value greater than zero. However, for this analysis the conservative approach is to assign no cost to the fuel. This approach reduces the uncontrolled boiler cost thereby increasing the impact of emission control costs.

[e]Unit landfill costs and credits are based on the unit costs and credits in EEA's Estimated Landfill Credit for Non-Fossil Fueled Boilers.[22] The costs for each boiler are based on the smallest-size landfill capable of absorbing ash and sludge from each model boiler. On-site landfills are assumed for all boilers except MSW-fired and RDF/coal cofired boilers. MSW and RDF/coal boilers feature off-site disposal 25 miles from the boiler operation.

TABLE 8-10. CAPITAL COSTS OF MODEL BOILERS, MID-1978 $ BASIS

Model Boiler Number	Boiler Capacity (Thermal Input Basis) MW	Boiler Capacity (Thermal Input Basis) 10^6 Btu/hr	Fuel[a]	Control Level[b] PM	Control Level[b] SO_2	Emission Control System[c]	Capital Cost, $1000 Boiler	Capital Cost, $1000 Emission Control	Capital Cost, $1000 Total	Unit Total Capital Cost, Fuel In Basis $/($10^6$ Btu/h)	Unit Total Capital Cost, Fuel In Basis $/kW	Unit Total Capital Cost, Steam Out Basis $/($10^6$ Btu/h)	Unit Total Capital Cost, Steam Out Basis $/kW	Unit Total Capital Cost, Steam Out Basis $/($10^3$ lbs steam/h)	Incremental Costs % Over Uncontrolled Boiler	Incremental Costs % Over Baseline Boiler
1a	8.8	30	Wood	B	B	MC	1800	98.3	1898	63,300	216	97,000	333	97,000	5.4	0
1b				I	B	MC,WS	1800	364	2164	72,100	246	111,000	380	110,000	20.2	14.0
1c				II	B	MC,WS	1800	389	2189	73,000	249	112,000	384	112,000	21.6	15.3
1d				II	B	MC,FF	1800	391	2191	73,000	249	112,000	384	112,000	21.7	15.4
1e				II	B	MC,ESP	1800	512	2312	77,100	263	119,000	406	118,000	28.4	21.8
2a	22.0	75	Wood	B	B	MC	3660	158	3818	50,900	174	78,400	267	77,900	4.3	0
2b				I	B	MC,WS	3660	565	4225	56,300	192	86,800	296	86,200	15.4	10.7
2c				II	B	MC,WS	3660	619	4279	57,100	195	87,900	299	87,300	16.9	12.1
2d				II	B	MC,FF	3660	773	4433	59,100	202	91,000	310	90,500	21.1	16.1
2e				II	B	MC,ESP	3660	978	4638	61,800	211	95,200	324	94,700	26.7	21.5
2f				II	B	MC,EGB	3660	890	4550	60,700	207	93,400	318	92,900	24.3	19.2
3a	44.0	150	Wood	B	B	MC	6130	311	6441	42,900	146	66,100	225	65,600	5.1	0
3b				I	B	MC,WS	6130	880	7010	46,700	159	71,900	245	71,400	14.4	8.8
3c				II	B	MC,WS	6130	1039	7169	47,800	163	73,500	251	73,000	16.9	11.3
3d				II	B	MC,FF	6130	1368	7498	50,000	170	76,900	262	76,400	22.3	16.4
3e				II	B	MC,ESP	6130	1309	7439	49,600	169	76,300	260	75,800	21.4	15.5
3f				II	B	MC,EGB	6130	1092	7222	48,100	164	74,100	253	73,500	17.6	12.1
4a	117	400	Wood	B	B	MC	13,500	673	14,173	35,400	121	51,500	186	63,600	5.0	0
4b				I	B	MC,WS	13,500	1701	15,201	38,000	129	55,500	200	68,200	12.6	7.3
4c				II	B	MC,WS	13,500	1929	15,429	38,600	132	59,300	203	69,200	14.3	8.9
4d				II	B	MC,FF	13,500	3044	16,544	41,400	141	63,600	217	74,200	22.5	16.7
4e				II	B	MC,ESP	13,500	2634	16,134	40,300	138	62,100	212	72,300	19.5	13.8
4f				II	B	MC,EGB	13,500	2470	15,970	39,900	136	61,400	210	71,600	18.3	12.7
5a	44.0	150	HAB	B	B	MC,WS	6230	822	7052	47,000	160	72,300	247	71,800	13.2	0
5b				I	B	MC,WS	6230	951	7181	47,900	163	73,700	251	73,100	15.3	1.8
5c				II	B	MC,FF	6230	1380	7610	50,700	173	78,100	266	77,500	22.2	7.9
6a	44.0	150	SLW	B	B	MC,WS	6130	1147	7277	48,500	165	74,600	254	74,100	18.7	0
6b				I	B	MC,WS	6130	1420	7550	50,300	172	77,400	264	76,900	23.2	3.8
6c				II	B	MC,FF	6130	1383	7513	50,100	171	77,100	263	76,500	22.6	3.2
7a	44.0	150	75% Wood/[d] 25% HSE	B	B	MC,WS	6870	921	7791	51,900	177	74,900	256	74,200	13.4	0
7b				I	B	MC,WS	6870	1077	7947	53,000	181	76,400	261	75,700	15.7	2.0
7c				I	I	MC,FGD-WS	6870	1861	8731	58,200	198	84,000	287	83,200	27.1	12.1
7d				II	B	MC,ESP	6870	1311	8181	54,500	186	78,700	269	77,900	19.1	5.0
7e				II	B	MC,FF	6870	1371	8241	54,900	187	79,200	271	78,500	20.0	5.8
7f				II	I	MC,FGD-DS,FF	6870	1884	8754	58,400	199	84,200	288	83,400	27.4	12.4
7g				II	II	MC,ESP,FGD-WS	6870	2593	9463	63,100	215	91,000	311	90,100	37.7	21.5
8a	44.0	150	50% Wood/[d] 50% HSE	B	B	MC,FGD-WS	7510	1644	9154	61,100	208	83,200	285	82,500	21.9	0
8b				I	B	MC,FGD-WS	7510	1797	9307	62,000	212	84,600	290	83,800	23.9	1.7
8c				I	I	MC,FGD-WS	7510	2002	9512	63,400	216	86,500	296	85,700	26.7	3.9
8d				I	II	MC,FGD-WS	7510	2061	9571	63,800	218	87,000	298	86,200	27.4	4.6
8e				II	B	MC,FGD-DS[e],FF	7510	1748	9258	61,700	210	84,200	288	83,400	23.3	1.1
8f				II	I	MC,FGD-DS,FF	7510	1958	9468	63,100	215	86,100	295	85,300	26.1	3.4
8g				II	II	MC,ESP,FGD-WS	7510	2738	10,248	68,300	233	93,200	319	92,300	36.5	12.0

See footnotes at end of table.

TABLE 8-10. (CONTINUED)

Model Boiler Number	Boiler Capacity (Thermal Input Basis)		Fuel[a]	Control Level[b]		Emission Control System[c]	Capital Cost, $1000			Unit Total Capital Cost					Incremental Costs	
										Fuel In Basis		Steam Out Basis				
	MW	10^6 Btu/hr		PM	SO_2		Boiler	Emission Control	Total	$/($10^6$ Btu/h)	$/kW	$/($10^6$ Btu/h)	$/kW	$/($10^3$ lbs steam/h)	% Over Uncontrolled Boiler	% Over Baseline Boiler
9a	117	400	50% Wood/[d] 50% HSE	B	B	MC,FGD-WS	16,700	3855	20,555	51,400	176	70,400	241	81,900	23.1	0
9b				I	I	MC,FGD-WS	16,700	3893	20,593	51,500	176	70,500	241	82,000	23.3	0.2
9c				II	I	MC,FGD-DS,FF	16,700	3733	20,433	51,100	175	70,000	239	81,400	22.4	-0.6
9d				II	II	MC,ESP,FGD-WS	16,700	5019	21,719	54,300	186	74,400	254	86,500	30.1	5.7
10a	44.0	150	50% Wood/[d] 50% LSW	B	B	MC,WS	7780	907	8687	57,900	197	79,000	271	78,300	11.7	0
10b				I	B	MC,WS	7780	1065	8845	59,000	201	80,400	276	79,700	13.7	1.8
10c				I	I	MC,FGD-WS	7780	1709	9489	63,300	216	86,300	296	85,500	22.0	9.2
10d				I	II	MC,FGD-WS	7780	1741	9521	63,500	216	86,600	297	85,800	22.4	9.6
10e				II	B	MC,FF	7780	1365	9145	61,000	208	83,100	285	82,400	17.5	5.3
10f				II	B	MC,ESP	7780	1279	9059	60,400	208	82,400	282	81,600	16.4	4.3
10g				II	I	MC,FGD-DS,FF	7780	1814	9594	64,000	218	87,200	299	86,400	23.3	10.4
10h				II	II	MC,ESP,FGD-WS	7780	2393	10,173	67,800	231	92,500	317	91,600	30.8	17.1
11a	44.0	150	50% RDF/[d] 50% HSE	B	B	FGD-WS	10,900	1817	12,717	84,800	289	112,000	381	122,000	16.7	0
11b				I	I	FGD-WS	10,900	2173	13,073	87,200	297	115,000	393	126,000	19.9	2.8
11c				I	II	FGD-WS	10,900	2233	13,133	87,600	299	115,000	393	126,000	20.5	3.3
11d				II	I	ESP,FGD-WS[e]	10,900	2537	13,437	89,600	305	118,000	402	129,000	23.3	5.7
11e				II	II	ESP,FGD-WS[e]	10,900	2609	13,509	90,100	307	119,000	405	130,000	23.9	6.2
12a	2.9	10	MSW	B	B	-	762	-	762	76,200	263	139,000	476	138,000	0	0
12b				I	B	WS	762	101	863	86,300	294	157,000	539	156,000	13.3	13.3
12c				II	B	FF	762	158	920	92,000	313	167,000	575	166,000	20.7	20.7
13a	44.0	150	MSW	B	B	ESP	16,500	1050	17,550	117,000	399	167,000	570	183,000	6.4	0
13b				I	B	ESP	16,500	1136	17,636	117,600	401	168,000	573	184,000	6.9	0.5
13c				II	B	ESP	16,500	1367	17,867	119,100	406	170,000	580	186,000	8.3	1.8
14a	117	400	MSW	B	B	ESP	35,300	1696	36,996	92,500	316	132,000	452	154,000	4.8	0
14b				I	B	ESP	35,300	2181	37,481	93,700	320	134,000	458	156,000	6.2	1.3
14c				II	B	ESP	35,300	2985	38,285	95,700	327	137,000	467	159,000	8.5	3.5
15a	58.6	200	Bagasse	B	B	MC	5450	402	5852	29,300	100	48,800	166	51,300	7.4	0
15b				I	B	WS	5450	1039	6489	32,400	111	54,100	184	56,900	19.1	10.9

[a]Wood - hog fuel (wood/bark mixture)
HAB - high ash bark
SLW - salt-laden wood
HSE - high sulfur eastern coal
LSW - low sulfur western coal
RDF - refuse derived fuel
MSW - municipal solid waste

[b]B refers to Baseline Control Level.
I refers to Control Level I.
II refers to Control Level II.

[c]MC - mechanical collector
WS - wet scrubber
FF - fabric filter
ESP - electrostatic precipitator
EGB - electrostatic gravel bed filter
FGD-WS - flue gas desulfurization; double alkali or lime wet scrubber
FGD-DS - flue gas desulfurization; lime dry scrubber
Control systems separated by a comma mean that both are used at the same time, not that either may be used independently.
Mechanical collectors are included for fly ash reinjection on all of the boilers firing wood.

[d]Average fuel mixture on a heat input basis.

[e]Only a portion of the flue gas is scrubbed.

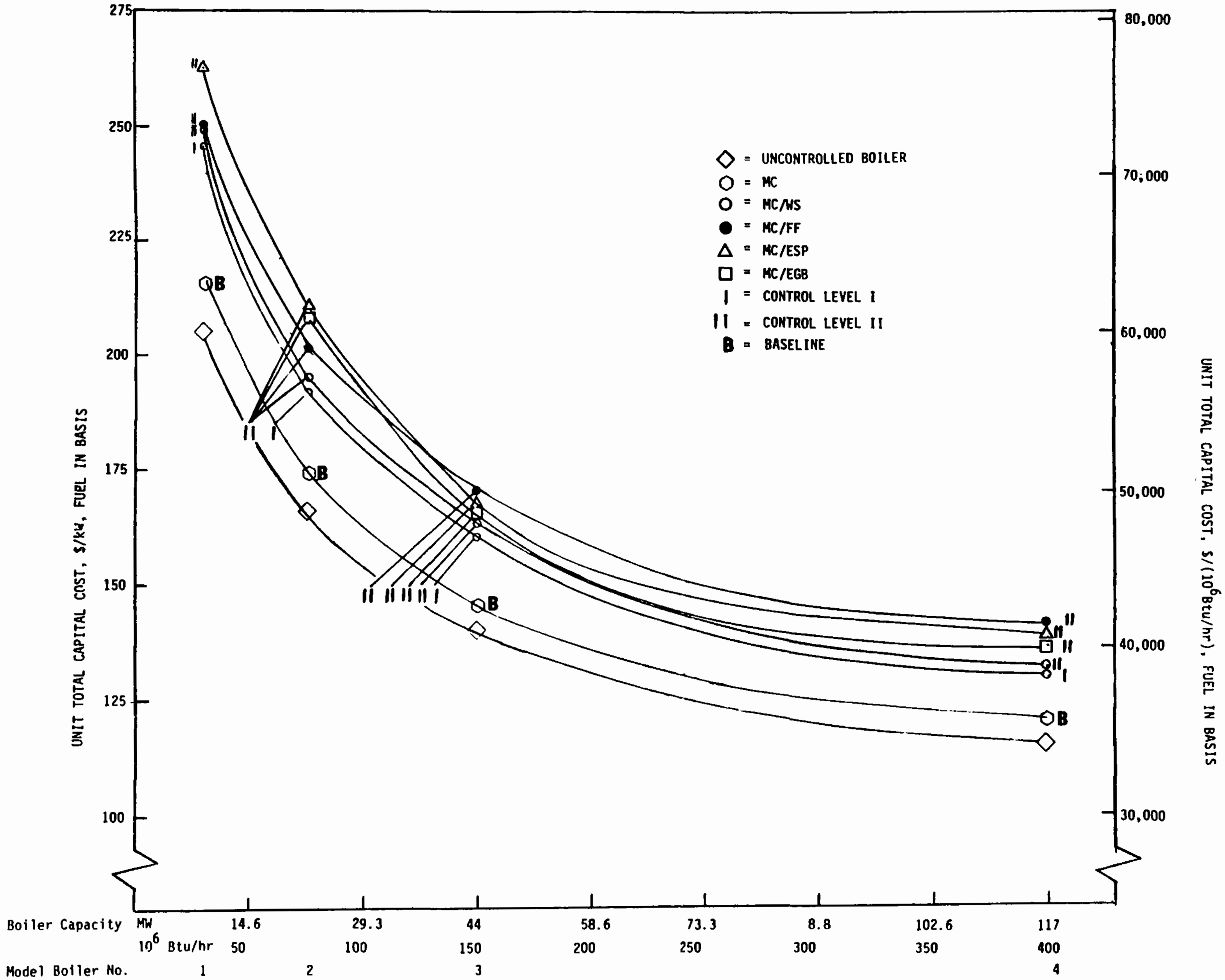


Figure 8-1. Unit total capital costs of wood-fired boilers, mid-1978 $ basis.

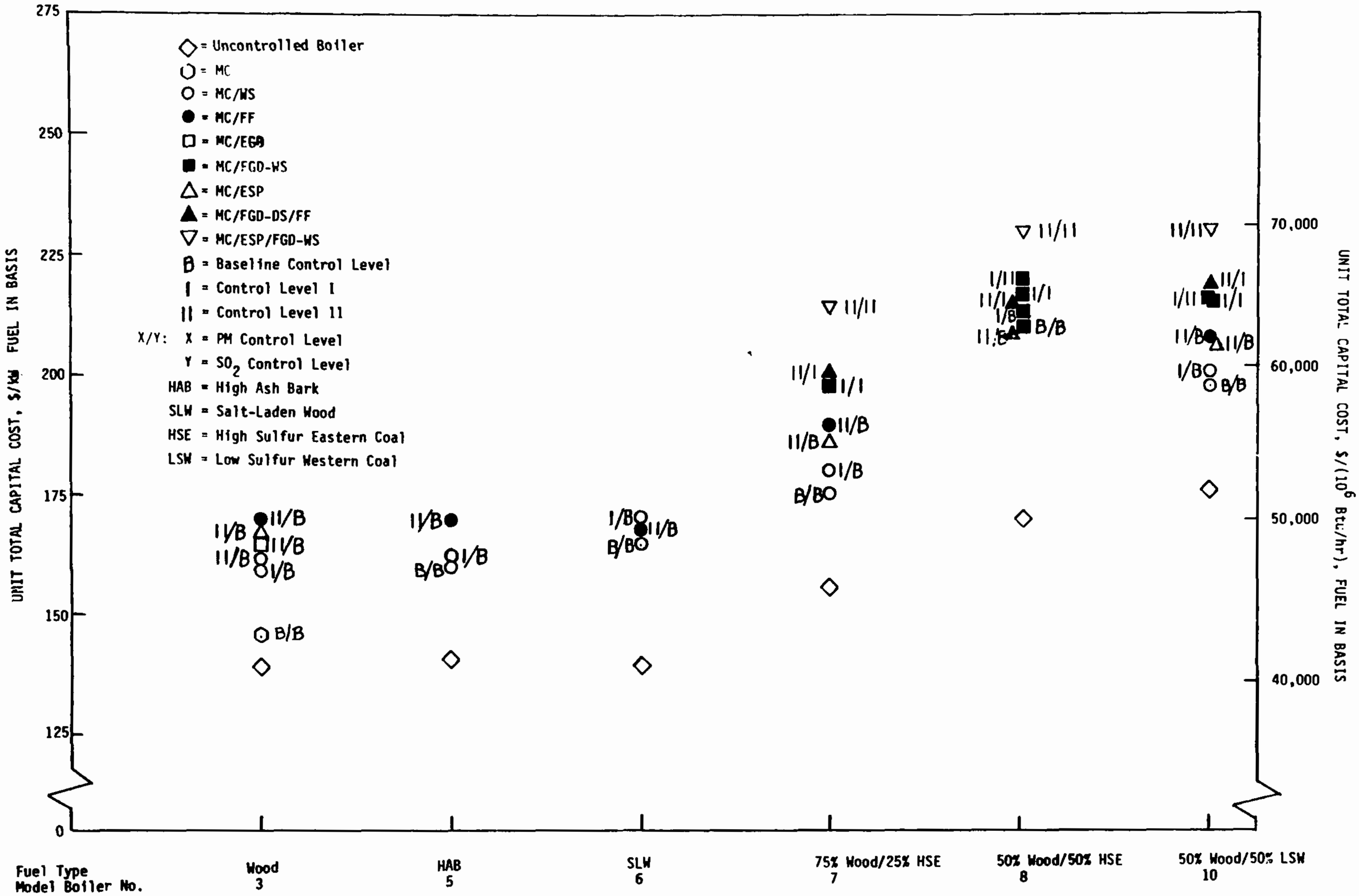


Figure 8-2. Unit total capital costs of 44 MW (150 x 10^6 Btu/hr) boilers firing various wood fuels and wood/coal combinations, mid-1978 $ basis.

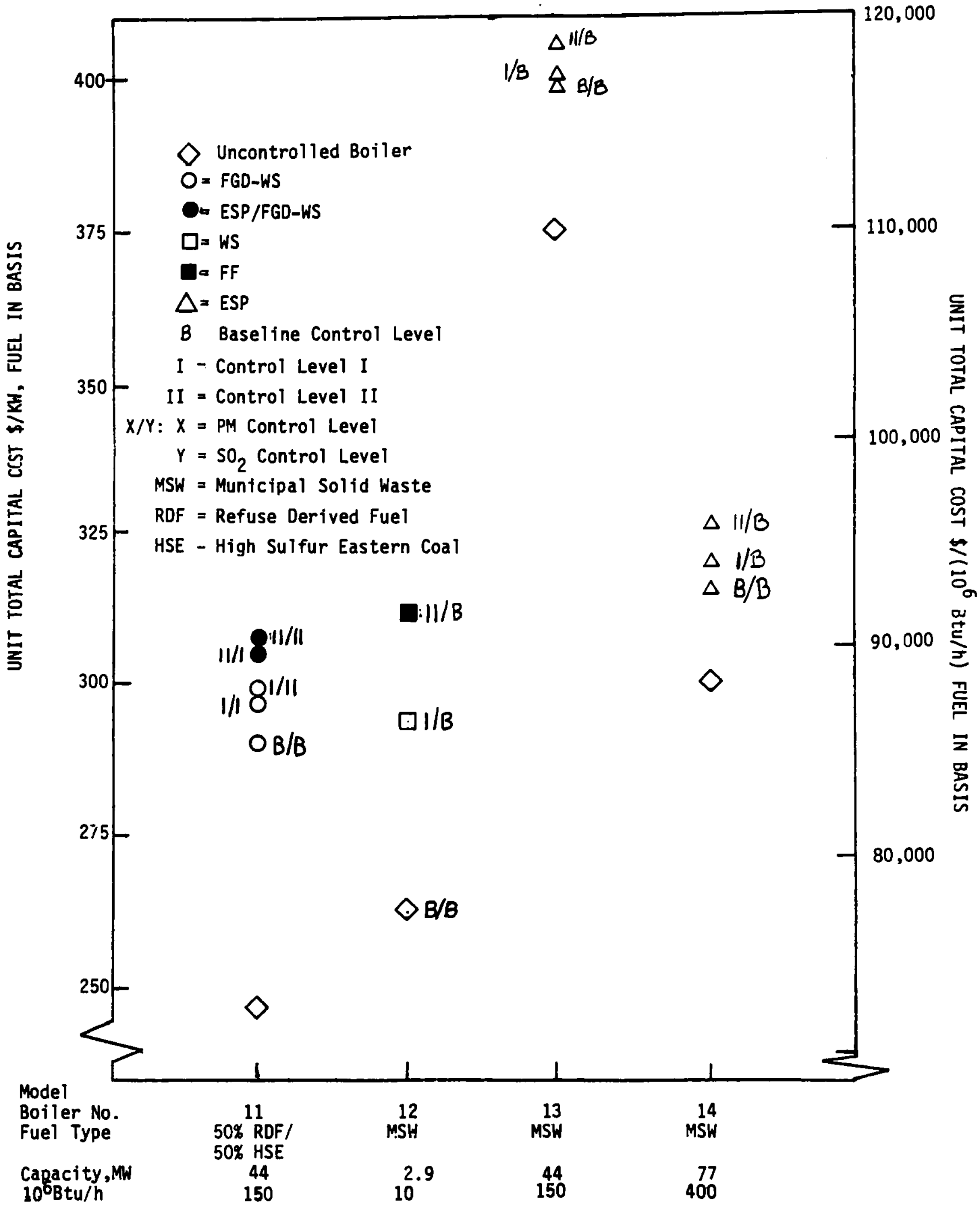


Figure 8-3. Unit total capital costs of model MSW-fired and RDF/coal cofired boilers, mid-1978 $ basis.

basis) while electrostatic gravel-bed filters have the next lowest capital costs for larger boilers (>32 MW). Electrostatic precipitators are less expensive than fabric filters for larger boilers (>32 MW).

8.1.2.1.2 Wood/Coal Cofired Boilers. Wood/coal cofired boilers controlled to PM Control Level I (with SO_2 controlled to the baseline level) show incremental capital cost impacts similar to those discussed above for wood-fired boilers. Boilers controlled to PM Control Level I are 1.7 to 2 percent more expensive than boilers controlled to the baseline level. Boilers controlled to PM Control Level II (with SO_2 controlled to the baseline level), are 1.1 to 5.8 percent more costly than boilers controlled to the baseline level, depending on the type of emission control system employed.

Boilers controlled to Control Level I for both SO_2 and PM are 0.2 - 12.1 percent more costly than boilers controlled to the baseline level. Boilers controlled to Control Level II for both SO_2 and PM have capital costs 5.7 to 21.5 percent greater than boilers controlled to the baseline level. For both of these control situations, the greatest incremental capital costs occur when the baseline control level requires no control of SO_2. The high incremental cost is thus due to the installation of equipment not needed to achieve baseline levels (e.g., raw material handling and regeneration modules).

For boilers of similar size, unit capital costs are greater for model boilers cofiring a 50/50 mixture of wood and high-sulfur eastern coal (HSE) than for model boilers firing a 75/25 mixture. The cost difference is mainly due to the increased cost of SO_2 control when more coal is fired.

Despite their lower emission control costs, boilers cofiring a 50/50 mixture of wood and low-sulfur western coal (LSW) are only slightly less expensive than boilers firing a 50/50 mixture of wood and HSE, and are more expensive than boilers firing a 75/25 mixture of wood and HSE. The relatively higher costs for boilers firing LSW and wood are due to higher uncontrolled boiler costs.

The model cofired boilers controlling both PM and SO_2 are more expensive than wood-fired boilers of similar size due to multiple fuel feeding systems and the use of SO_2 control systems. Cofired boilers controlling only PM are more expensive than their wood-fired counterparts due to multiple fuel feeding systems and the use of corrosion-resistant construction materials (for scrubbers).

8.1.2.1.3 RDF/Coal Cofired Boilers. RDF/coal cofired boilers controlled to Control Level I for both SO_2 and PM have capital costs 2.8 percent greater than boilers controlled to the baseline control level. Boilers controlled to Control Level II for both SO_2 and PM have capital costs 6.2 percent greater than boilers controlled to the baseline control level.

The model RDF/coal cofired boilers have higher emission control costs than MSW-fired boilers of similar size due to the use of SO_2 control systems in the cofired boilers. The uncontrolled RDF/coal boilers are less expensive than the uncontrolled MSW-fired boilers due to differences in facility scope: The RDF/coal cofired boilers are used in industrial settings and share support facility costs with other plant operations. Costs for the MSW-fired boilers do not allow a similar sharing of support facility costs and additionally include equipment not used in an RDF/coal cofired facility.

8.1.2.1.4 MSW-Fired Boilers. Large mass-burn type MSW boilers controlled to PM Control Level I have capital costs 0.5 to 1.3 percent greater than boilers controlled to the baseline level. Mass-burn boilers controlled to Control Level II have capital costs 1.8 to 3.5 percent greater than baseline boilers.

Small modular boilers show more significant impacts, with boilers controlled to PM Control Level I costing 13.3 percent more than boilers controlled to the baseline control level. Small modular boilers controlled to PM Control Level II cost 20.7 percent more than boilers controlled to the baseline level. These boilers can achieve the baseline level without any particulate matter controls. The high incremental costs are thus due to the installation of equipment not needed to achieve baseline levels.

The small modular boilers have lower unit capital costs than the large mass-burn type boilers due to differences in facility scope and to differences in boiler design. The large mass-burn boilers, for example, feature more heat exchange surface than the modular boilers to achieve greater heat recoveries.

8.1.2.1.5 Bagasse-Fired Boilers. Bagasse-fired boilers controlled to PM Control Level I have capital costs 10.9 percent greater than the baseline boilers. Control Level I requires the use of a wet scrubber while the baseline control level can be attained through the use of a mechanical collector.

8.1.2.2 Annualized Costs. Annualized costs for the model boilers are summarized in Table 8-11 and graphically portrayed in Figures 8-4, 8-5, and 8-6. The annualized costs are reported both in total dollars per year and in dollars per unit energy input or output. These costs are discussed below by fuel type.

8.1.2.2.1 Wood-Fired Boilers. Annualized costs for wood-, HAB-, or SLW-fired boilers controlled to PM Control Level I are 2.0 to 8.9 percent greater than costs for boilers controlled to the baseline level. The incremental costs for Control Level I for wood-fired boilers are higher than those for HAB- or SLW-fired boilers. This is because wood-fired boilers use mechanical collectors for baseline control and HAB- and SLW-fired boilers use wet scrubbers. Wood- and HAB-fired boilers controlled to PM Control Level II are 3.0 to 12.0 percent more costly than boilers controlled to the baseline control level; the incremental costs vary with boiler size and type of emission control.

SLW-fired boilers controlled to PM Control Level II have annualized costs 0.7 percent less than boilers controlled to the baseline level. Because of the high pressure drop needed for particulate removal and because the scrubbers must be constructed of expensive, corrosion- resistant SS316, fabric filters achieving the stringent control level are less expensive than scrubbers used for baseline. This outcome explains the growing use of fabric filters on boilers firing this type of wood.

As shown in Figure 8-4, model boiler costs on a unit energy basis decrease with system size due to boiler and emission control economies of scale. Figure 8-5 also shows that HAB-fired and SLW-fired boilers produce

TABLE 8-11. ANNUALIZED COSTS OF MODEL BOILERS, MID-1978 $ BASIS

Model Boiler Number	Boiler Capacity (Thermal Input Basis) MW	Boiler Capacity (Thermal Input Basis) 10^6Btu/hr	Fuel[a]	Control Level[b] PM	Control Level[b] SO_2	Emission Control System[c]	Annualized Cost,[f] $1000 Boiler	Annualized Cost,[f] $1000 Emission Control	Annualized Cost,[f] $1000 Total	Unit Total Annualized Cost: Fuel In Basis $/($10^6$Btu)	Fuel In Basis $/GJ	Steam Out Basis $/($10^6$Btu)	Steam Out Basis $/GJ	Steam Out Basis $/($10^3$lbs steam)	Incremental Costs: % Over Uncontrolled Boiler	Incremental Costs: % Over Baseline Boiler
1a	8.8	30	Wood	B	B	MC	841	55.8	897	5.69	5.39	8.75	8.30	8.71	6.7	0
1b				I	B	MC,WS	841	136	977	6.20	5.87	9.53	9.04	9.48	16.2	8.9
1c				II	B	MC,WS	841	147	988	6.27	5.94	9.64	9.14	9.59	17.5	10.1
1d				II	B	MC,FF	841	127	968	6.14	5.82	9.44	8.95	9.40	15.1	7.9
1e				II	B	MC,ESP	841	140	981	6.22	5.90	9.57	9.07	9.52	16.6	9.4
2a	22.0	75	Wood	B	B	MC	1469	87.2	1556	3.95	3.74	6.08	5.76	6.04	5.9	0
2b				I	B	MC,WS	1469	226	1695	4.30	4.08	6.62	6.28	6.58	15.4	8.9
2c				II	B	MC,WS	1469	252	1721	4.37	4.14	6.72	6.37	6.68	17.2	10.6
2d				II	B	MC,FF	1469	240	1709	4.34	4.11	6.68	6.33	6.64	16.3	9.8
2e				II	B	MC,ESP	1469	256	1725	4.38	4.15	6.74	6.39	6.70	17.4	10.9
2f				II	B	MC,EGB	1469	243	1712	4.34	4.12	6.69	6.34	6.65	16.5	10.0
3a	44.0	150	Wood	B	B	MC	2173	129	2302	2.92	2.77	4.49	4.26	4.46	5.9	0
3b				I	B	MC,WS	2173	331	2504	3.18	3.01	4.89	4.63	4.85	15.2	8.8
3c				II	B	MC,WS	2173	392	2565	3.25	3.08	5.01	4.74	4.97	18.0	11.4
3d				II	B	MC,FF	2173	380	2553	3.24	3.07	4.98	4.72	4.95	17.5	10.9
3e				II	B	MC,ESP	2173	336	2509	3.18	3.02	4.90	4.64	4.86	15.5	9.0
3f				II	B	MC,EGB	2173	303	2476	3.14	2.98	4.83	4.58	4.80	13.9	7 6
4a	117	400	Wood	B	B	MC	4563	288	4851	2.31	2.19	3.55	3.36	4.14	6.3	0
4b				I	B	MC,WS	4563	705	5268	2.51	2.38	3.85	3.65	4.49	15.5	8.6
4c				II	B	MC,WS	4563	827	5390	2.56	2.43	3.94	3.74	4.60	18.1	11.1
4d				II	B	MC,FF	4563	868	5431	2.58	2.45	3.97	3.77	4.63	19.0	12.0
4e				II	B	MC,ESP	4563	708	5271	2.51	2.38	3.86	3.66	4.50	15.5	8.7
4f				II	B	MC,EGB	4563	692	5255	2.50	2.37	3.85	3.64	4.48	15.2	8.3
5a	44.0	150	HAB	B	B	MC,WS	2210	323	2533	3.21	3.05	4.94	4.69	4.91	14.8	0
5b				I	B	MC,WS	2210	373	2583	3.28	3.11	5.04	4.78	5.00	16.9	2.0
5c				II	B	MC,FF	2210	399	2609	3.31	3.14	5.09	4.83	5.05	18.1	3.0
6a	44.0	150	SLW	B	B	MC,WS	2173	411	2584	3.28	3.11	5.04	4.78	5.01	18.9	0
6b				I	B	MC,WS	2173	498	2671	3.39	3.21	5.21	4.94	5.17	22.9	3.4
6c				II	B	MC,FF	2173	392	2565	3.25	3.08	5.01	4.74	4 97	18.0	-0.7
7a	44.0	150	75% Wood/[d] 25% MSE	B	B	MC,WS	2467	323	2790	3.54	3.35	5.10	4.84	5.06	13.1	0
7b				I	B	MC,WS	2467	377	2844	3.61	3.42	5.20	4.93	5.15	15.3	1.9
7c				I	I	MC,FGD-WS	2467	786	3253	4.13	3.91	5.95	5.64	5.89	31.9	16.6
7d				II	B	MC,ESP	2467	339	2806	3.56	3.37	5.13	4.87	5.08	13.7	0.6
7e				II	B	MC,FF	2467	385	2852	3.62	3.43	5.22	4.95	5.17	15.6	2.2
7f				II	I	MC,FGD-DS,FF	2467	753	3220	4.08	3.87	5.89	5.58	5.83	30.5	15.4
7g				II	II	MC,ESP,FGD-WS	2467	968	3435	4.36	4.13	6.28	5.96	6.22	39.2	23.1
8a	44.0	150	50% Wood/[d] 50% MSE	B	B	MC,FGD-WS	2712	695	3407	4.32	4.10	5.89	5.59	5.84	25.6	0
8b				I	B	MC,FGD-WS	2712	746	3458	4.39	4.16	5.98	5.67	5.93	27.5	1.5
8c				I	I	MC,FGD-WS	2712	868	3580	4.54	4.30	6.19	5.87	6.14	32.0	5.1
8d				I	II	MC,FGD-WS	2712	907	3619	4.59	4.35	6.26	5.93	6.20	33.4	6.2
8e				II	B	MC,FGD-DS[e],FF	2712	695	3407	4.32	4.10	5.89	5.59	5.84	25.6	0
8f				II	I	MC,FGD-DS,FF	2712	816	3528	4.47	4.24	6.10	5.78	6.05	30.1	3.6
8g				II	II	MC,ESP,FGD-WS	2712	1061	3773	4.79	4.54	6.53	6.19	6.47	39.1	10.7

See footnotes at end of table.

TABLE 8-11. (CONTINUED)

Model Boiler Number	Boiler Capacity (Thermal Input Basis)		Fuel[a]	Control Level[b]		Emission Control System[c]	Annualized Cost,[f] $1000			Unit Total Annualized Cost					Incremental Costs	
										Fuel In Basis		Steam Out Basis				
	MW	10^6 Btu/hr		PM	SO_2		Boiler	Emission Control	Total	$/($10^6$ Btu)	$/GJ	$/($10^6$ Btu)	$/GJ	$/($10^3$ lbs steam)	% Over Uncontrolled Boiler	% Over Baseline Boiler
9a	117	400	50% Wood/[d]	B	B	MC,FGD-WS	5899	1380	7279	3.46	3.28	4.74	4.50	5.52	23.4	0
9b			50% HSE	I	I	MC,FGD-WS	5899	1416	7315	3.48	3.30	4.77	4.52	5.54	24.0	0.5
9c				II	I	MC,FGD-DS,FF	5899	1313	7212	3.43	3.25	4.70	4.45	5.47	22.3	-0.9
9d				II	II	MC,ESP,FGD-WS	5899	1741	7640	3.63	3.44	4.99	4.72	5.79	29.5	5.0
10a	44.0	150	50% Wood/[d]	B	B	MC,WS	2517	311	2928	3.71	3.52	5.06	4.80	5.02	11.9	0
10b			50% LSW	I	B	MC,WS	2617	365	2982	3.78	3.59	5.16	4.89	5.11	13.9	1.8
10c				I	I	MC,FGD-WS	2617	720	3337	4.23	4.01	5.77	5.47	5.72	27.5	14.0
10d				I	II	MC,FGD-WS	2517	733	3350	4.25	4.03	5.79	5.49	5.74	28.0	14.4
10e				II	B	MC,FF	2617	381	2998	3.80	3.60	5.19	4.92	5.14	14.6	2.4
10f				II	B	MC,ESP	2617	333	2950	3.74	3.55	5.10	4.84	5.06	12.7	0.8
10g				II	I	MC,FGD-DS,FF	2617	709	3326	4.22	4.00	5.75	5.45	5.70	27.1	13.6
10h				II	II	MC,ESP,FGD-WS	2617	890	3507	4.45	4.22	6.07	5.75	6.01	34.0	19.8
11a	44.0	150	50% RDF/[d]	B	B	FGD-WS	3468	755	4223	5.36	5.08	7.05	6.68	7.73	21.8	0
11b			50% HSE	I	I	FGD-WS	3468	896	4364	5.54	5.25	7.28	6.90	7.98	25.8	3.3
11c				I	II	FGD-WS	3468	931	4399	5.58	5.29	7.34	6.96	8.05	26.8	4.2
11d				II	I	ESP,FGD-WS	3468	964	4432	5.62	5.33	7.40	7.01	8.11	27.8	4.9
11e				II	II	ESP,FGD-US	3468	1002	4470	5.67	5.37	7.46	7.07	8.18	28.9	5.8
12a	2.9	10	MSW	B	B	-	212	-	212	4.03	3.82	7.33	6.95	7.28	0	0
12b				I	B	WS	212	71	283	5.38	5.10	9.79	9.28	9.72	33.5	33.5
12c				II	B	FF	212	76	288	5.48	5.19	9.96	9.44	9.89	35.8	35.8
13a	44.0	150	MSW	B	B	ESP	1667	272	1939	2.46	2.33	3.51	3.33	3.84	16.3	0
13b				I	B	ESP	1667	289	1956	2.48	2.35	3.54	3.36	3.88	17.3	0.9
13c				II	B	ESP	1667	334	2001	2.54	2.41	3.63	3.44	3.97	20.0	2.2
14a	117	400	MSW	B	B	ESP	3056	486	3542	1.68	1.60	2.41	2.28	2.80	15.9	0
14b				I	B	ESP	3056	574	3630	1.72	1.64	2.47	2.34	2.87	18.8	2.5
14c				II	B	ESP	3056	723	3779	1.80	1.70	2.57	2.43	2.98	23.7	6.7
15a	58.6	200	Bagasse	B	B	MC	1597	143	1740	2.21	2.09	3.68	3.49	3.87	9.0	0
15b				I	B	WS	1597	370	1967	2.43	2.36	4.16	3.94	4.38	23.2	13.0

[a]Wood - hog fuel (wood/bark mixture)
HAB - high ash bark
SLW - salt-laden wood
HSE - high sulfur eastern coal
LSW - low sulfur western coal
RDF - refuse derived fuel
MSW - municipal solid waste

[b]B refers to Baseline Control Level.
I refers to Control Level I.
II refers to Control Level II.

[c]MC - mechanical collector
WS - wet scrubber
FF - fabric filter
ESP - electrostatic precipitator
EGB - electrostatic gravel bed filter
FGD-WS - flue gas desulfurization; double alkali or lime wet scrubber
FGD-DS - flue gas desulfurization; lime dry scrubber
Control systems separated by a comma mean that both are used at the same time, not that either may be used independently.
Mechanical collectors are included for fly ash reinjection on all of the boilers firing wood.

[d]Average fuel mixture on a heat input basis.

[e]Only a portion of the flue gas is scrubbed.

[f]The annualized costs for model MSW-fired boilers include credits from removing the need to dispose of MSW. These credits are equivalent to the "tipping fees" charged for landfilling. Removing this credit from the tabulated annualized costs increases the model boiler costs by the amount of the credit (which is reported below):

Model Boiler Number	Waste Disposal Credit $1000	Unit Waste Disposal Credit				
		Fuel In Basis		Steam Out Basis		
		$/$10^6$Btu	$/GJ	$/$10^6$Btu	$/GJ	$/$10^3$lbs steam
12a-c	178	3.38	3.20	6.15	5.83	6.11
13a-c	1914	2.43	2.30	3.47	3.29	3.45
14a-c	5097	2.42	2.29	3.46	3.28	3.44

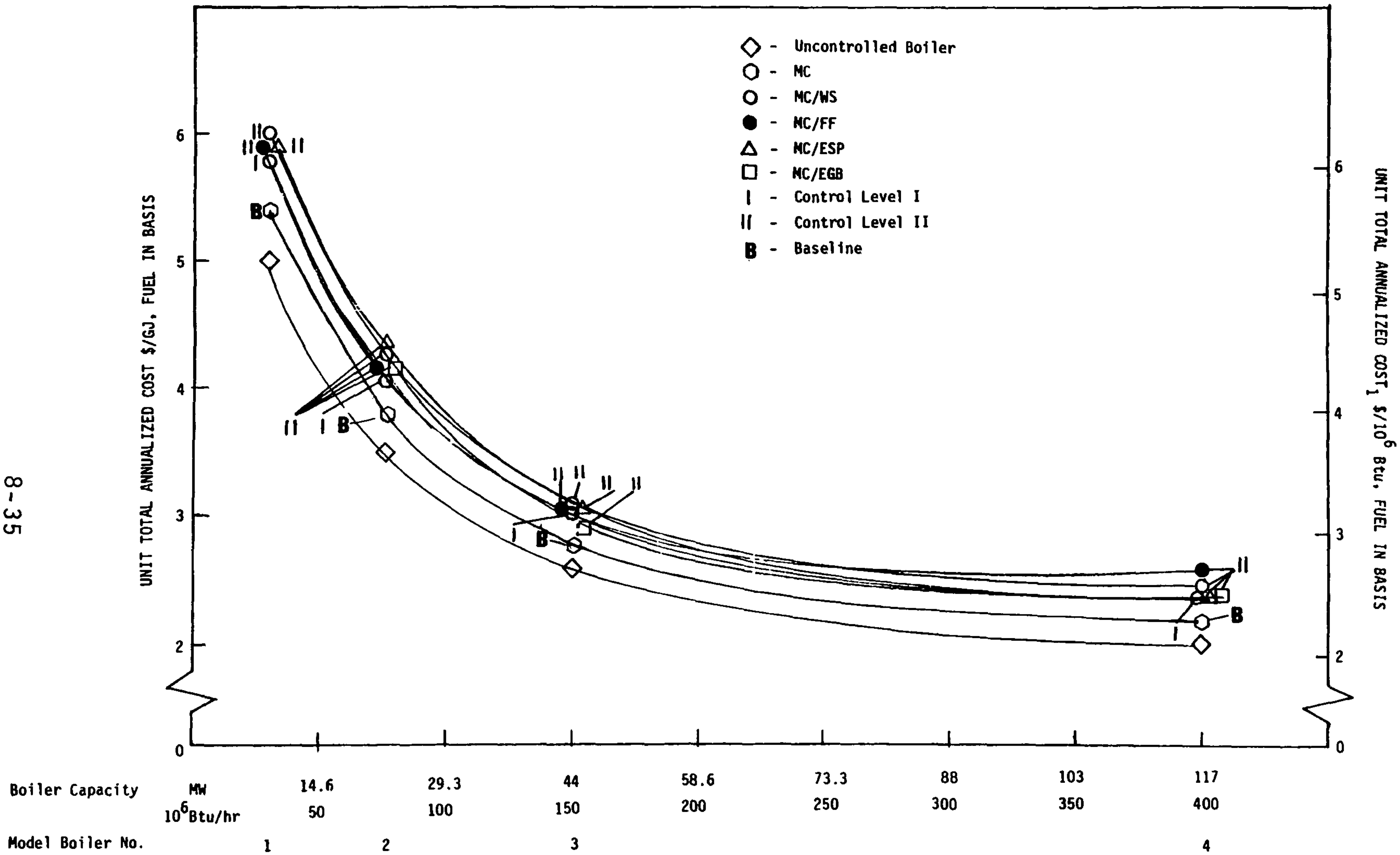


Figure 8-4. Unit total annualized costs for wood-fired boilers, mid-1978 $ basis.

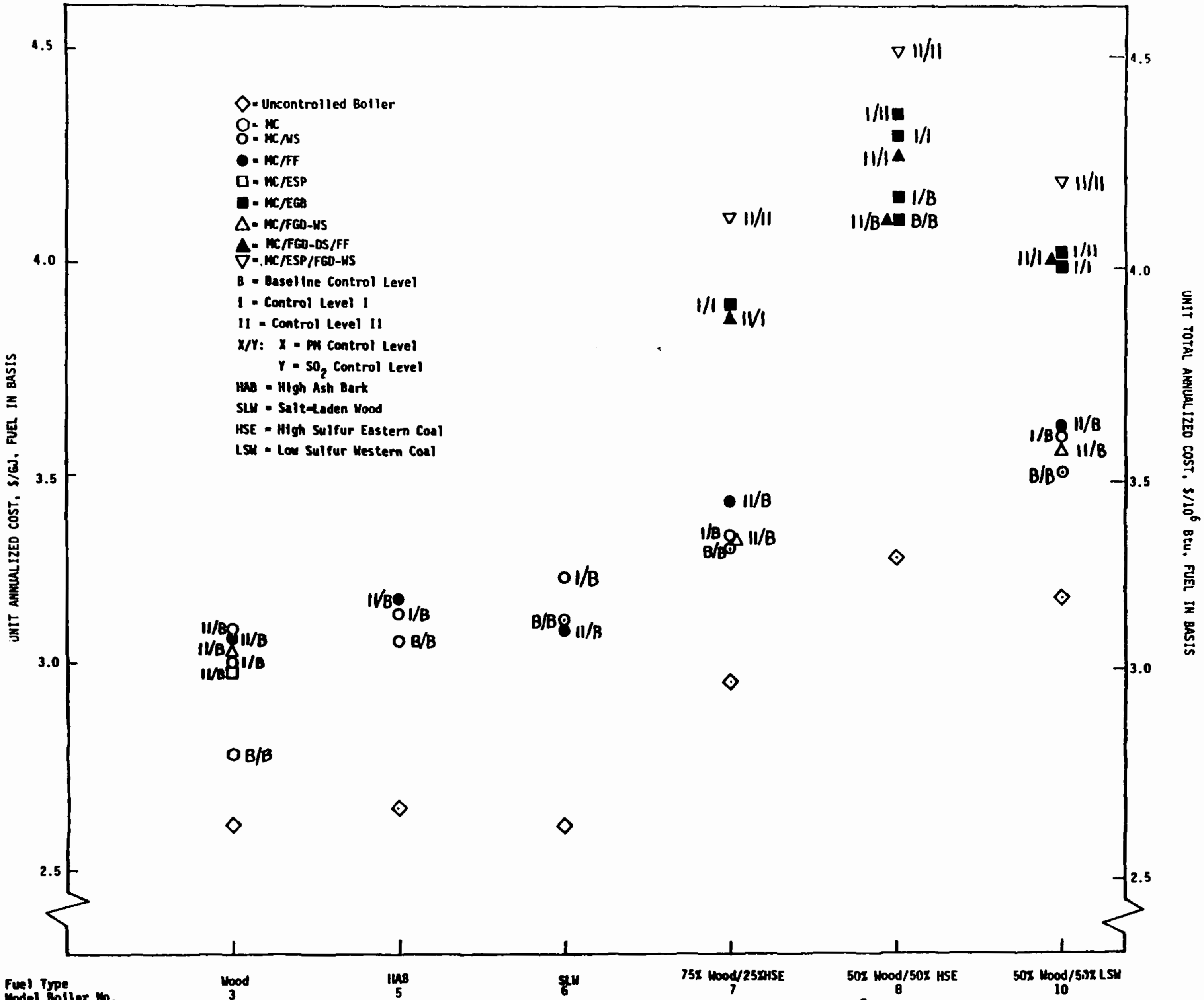
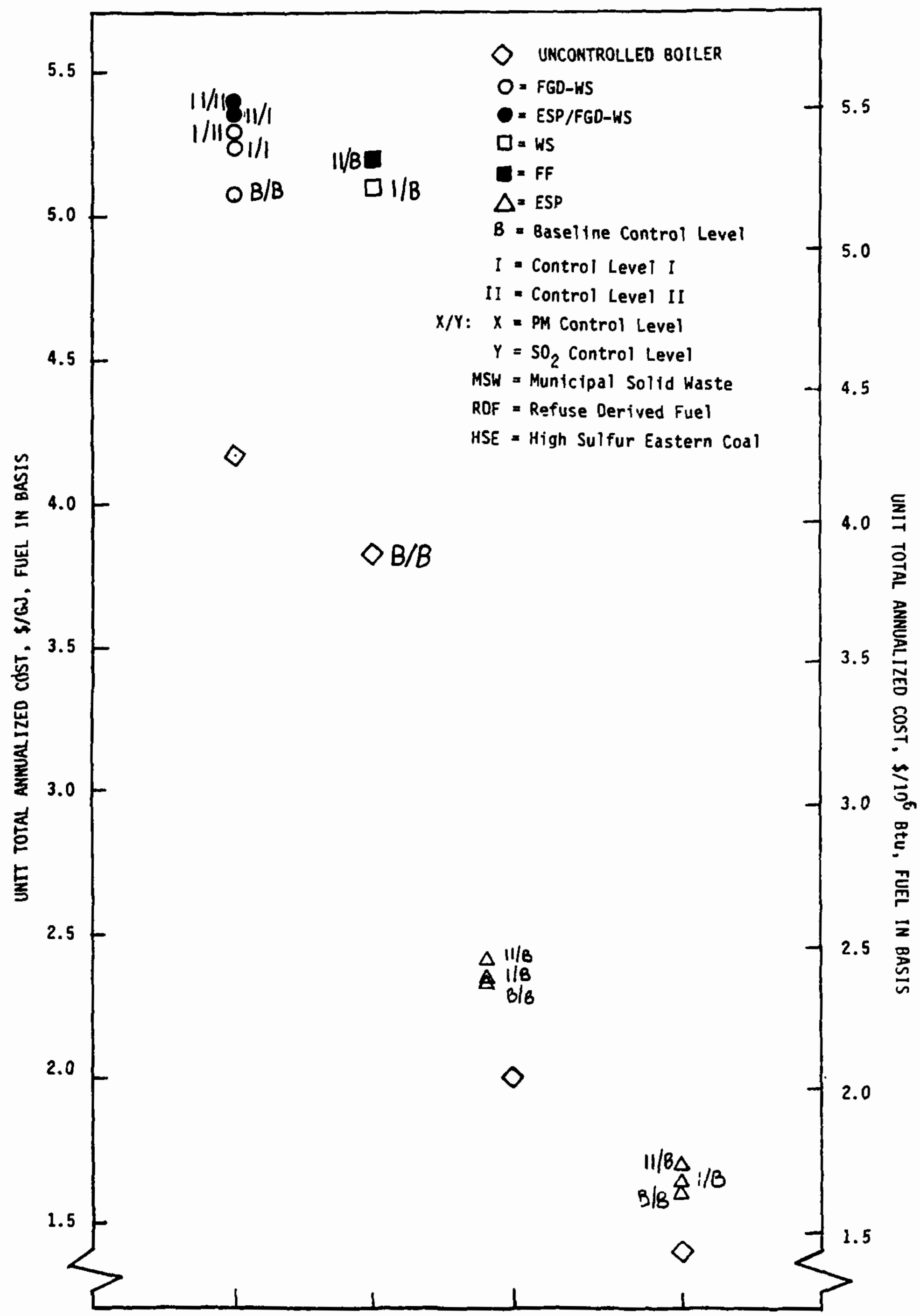


Figure 8-5. Unit total annualized costs of 44 MW (150×10^6 Btu/hr) boilers firing various wood fuels and wood/coal combinations, mid-1978 $ basis.



Model Boiler No.	11	12	13	14
Fuel Type	50% RDF/ 50% HSE	MSW	MSW	MSW
Boiler Capacity MW	44	2.9	44	117
(10^6Btu/h)	150	10	150	400

Figure 8-6. Unit total annualized costs of model MSW-fired and RDF/coal cofired boilers, mid-1978 \$ basis.

steam at only slightly higher cost than wood-fired boilers controlled to similar control levels.

Of the four emission control systems capable of achieving PM Control Level II (WS, FF, ESP, EGB), fabric filters are the least expensive option for small boilers (<32 MW on a thermal input basis). Electrostatic gravel-bed filters appear to be the least expensive control option for the larger systems, but the reader should recognize that electrostatic gravel-bed filtration is a developing technology whose costs and performance are less certain than for the other technologies. Electrostatic precipitators are the next least expensive control option for the larger systems.

8.1.2.2.2 Wood/Coal Cofired Boilers. Wood/coal cofired boilers controlled to PM Control Level I (with SO_2 controlled to the baseline level) show incremental annualized cost impacts less than those discussed for wood-fired boilers because of the difference in the baseline control level. Boilers controlled to PM Control Level I are 1.5 to 1.9 percent more expensive than boilers controlled to the baseline level. Boilers controlled to PM Control Level II (with SO_2 controlled to the baseline level) are 0 to 2.4 percent more expensive than boilers controlled to the baseline level, depending on the type of emission control system employed. (The boiler system achieving PM Control Level II at no incremental annualized cost uses a dry scrubbing system for SO_2 removal to the baseline level. Since the dry scrubbing system is less expensive than the wet scrubbing system used for baseline SO_2 control, a more expensive PM control system can be used with the dry scrubbing system without increasing the annualized cost relative to the base case.)

Boilers controlled to Control Level I for both SO_2 and PM are 0.5 to 16.6 percent more costly than boilers controlled to the baseline level. Boilers controlled to Control Level II for both SO_2 and PM are 5.0 to 23.1 percent more expensive than boilers controlled to the baseline level. For both of these control situations, the greatest incremental annualized costs occur when the baseline level requires no control of SO_2. The high incremental cost is thus due to the installation and operation of equipment not needed to achieve baseline levels. The low incremental costs are associated with the 117 MW boilers which are subject to the existing NSPS (40 CFR 60 Subpart D) which requires efficient SO_2 and PM controls at baseline.

For the model wood/coal cofired boilers of similar size, unit annualized costs are greatest for boilers cofiring a 50/50 mixture of wood and HSE, mainly due to the cost of SO_2 control. Of the model wood/coal cofired boilers, boilers cofiring a 50/50 mixture of wood and LSW have the lowest annualized control costs although total annualized costs are slightly higher than the boilers cofiring a 75/25 mixture of wood and HSE.

8.1.2.2.3 RDF/Coal Cofired Boilers. RDF/coal cofired boilers controlled to Control Level I for both SO_2 and PM have annualized costs 3.3 percent greater than boilers controlled to the baseline control level. Boilers controlled to Control Level II for both pollutants have annualized costs 5.8 percent greater than boilers controlled to the baseline control level.

8.1.2.2.4 MSW-Fired Boilers. Large mass-burn type MSW boilers controlled to PM Control Level I have annualized costs 0.9 to 2.5 percent greater than boilers controlled to the baseline level. Mass-burn boilers controlled to PM Control Level II have annualized costs 3.2 to 6.7 percent greater than baseline boilers.

Again, small modular boilers show more significant cost impacts than the large mass-burn boilers, with boilers controlled to PM Control Level I costing 33.5 percent more than boilers controlled to the baseline level. Boilers controlled to PM Control Level II have annualized costs 35.8 percent greater than boilers controlled to the baseline level.

8.1.2.2.5 Bagasse-Fired Boilers. Bagasse-fired boilers controlled to PM Control Level I have annualized costs 13.0 percent greater than the baseline boilers.

8.1.2.2.6 Variability of Annualized Costs of Wet Scrubbers. The costs presented in Table 8-11 for wet scrubbers are based on conservatively designed systems. Therefore, the actual costs for new installations could be considerably less than the costs shown in Table 8-11. For example, the annualized cost of the wet scrubber emission control system for model boiler

15b could potentially be 32 percent less than the cost shown if waste water treatment is already available on-site.[26] The annualized costs for the combined mechanical collector/wet scrubber systems shown for model boilers 1-4 could potentially be 19 to 23 percent less depending on cost of waste water treatment, solid waste disposal, and the type of mechanical collector precleaner used.[26] Some of these factors could also affect the costs of the other types of controls shown in Table 8-11.

8.1.3 Modified/Reconstructed Facilities

Under the provisions of 40 CFR 60.14 and 60.15, an "existing facility" may become subject to standards of performance if deemed modified or reconstructed. In such situations control devices would have to be installed for compliance with new source performance standards.

Due to special considerations, the cost for installing a control system in an existing boiler facility is generally greater than the cost of installing the control system on a new facility. However, since retrofit costs are highly site-specific, they are difficult to estimate. Examples of these site-specific factors are availability of space and the potential need for additional ducting.

Configuration of equipment in the plant governs the location of the control system. For instance, if the boiler stack is on the roof of the boiler house, the control system may have to be placed at ground level, requiring long ducting runs from the ground level to the stack. If the available space at the plant is inadequate to accommodate the control equipment, it may be necessary to install the equipment on the roof of an adjacent building, thus requiring the addition of structural steel support. It has been estimated that roof top installation can double the structural costs for installation of the control system. Foundations and structural support costs typically amount to 2-3 percent of the control system capital costs.[27]

Other capital cost components that may increase because of space restrictions and plant configurations are contractor and engineering fees (typically 15-25 percent of the control system capital cost),[27] construction and labor expenses, and interest charges during construction (because of longer construction periods).

8.1.4 National Cost Impacts

Table 8-12 summarizes the nationwide cost impact in 1990 of applying PM emission controls to new NFFBs to meet each of the PM emission control levels. The cost impact resulting from any NSPS for nonfossil fuel-fired boilers will be dependent on the control level required and the boiler population affected. The boiler population growth estimates are based on estimates of the growth of potential NFFB user categories.[28]

As discussed in Chapter 6, the current PM emission regulations for wood-fired boilers vary considerably from state to state. Therefore, a varying mix of control methods will be used to meet existing regulations in the absence of an NSPS. The two control methods typically used for wood-fired boilers are mechanical collectors (MC) or mechanical collector/wet scrubbers in series (MC/WS). The national cost of the Baseline Control Level is based on the weighted average cost of these two systems.

The mix of these two systems is based on the percentage of each required to produce a national emission level equal to the average of the existing State regulations. To determine this mix, the MC systems were assumed to have emission rates of 258 ng/J (0.6 lb/10^6Btu). A "typical" MC/WS system used to meet existing state regulations is assumed to have an emission rate of 86 ng/J (0.2 lb/10^6 Btu) and a pressure drop of 1.7 kPa (7 inches w.c.) based on the data for low pressure drop scurbbers shown in Figure 4.1-22 in Chapter 4. The costs of these MC/WS systems were developed from the same cost bases used for the MC/WS costs shown in Table 8-11.

The national costs for Control Levels other than baseline for wood and bagasse are based on MC/WS and WS control systems, respectively. The cost ranges are due to the variability in scrubber costs discussed in Section 8.1.2.2.6. For wood, the national costs for ESPs and fabric filters would be expected to fall with the ranges shown for wet scrubbers.

TABLE 8-12. NATIONAL EMISSION CONTROL ANNUALIZED COSTS FOR NONFOSSIL FUEL FIRED BOILERS IN 1990[a]

Fuel	Baseline	Annualized Cost of Control Systems - 10^6 \$ Control Level I	Control Level II
Wood[b,f]	60.6 - 75.3	74.7 - 97.3	88.3 - 112.6
GSW[c,d]	26.1	30.2	37.1
GSW[c,e]	0	29.5	31.6
Bagasse[f]	6.3	10.9 - 15.5	-

[a]The reported costs are the annualized costs of control for nonfossil fuel-fired boilers potentially affected by New Source Performance Standards. This would be the cumulative nonfossil fuel fired boiler capacity installed in 1984 to the end of 1990. The costs are for the emission control system only and are in mid-1978 dollars.

[b]The national impact of emission control on wood-fired boiler costs is estimated from the costs for model boilers firing "typical" wood fuels. (The firing of other wood fuel types was evaluated in the model boiler analysis to determine the sensitivity of emission control costs to wood ash and salt contents.)

[c]GSW - general solid waste. This includes all municipal-type solid waste fuels and refuse derived fuels.

[d]Includes all MSW- and RDF-fired boilers except small modular units. RDF-fired boilers are assumed to fire 100 percent RDF. The costs of control for 100 percent RDF-fired boilers are assumed to be similar to those for MSW-fired boilers based on the similarity of control equipment design.

[e]Includes only small modular GSW-fired boilers.

[f]The cost ranges are due to the variability in wet scrubber costs discussed in Section 8.1.2.2.6.

8.2 OTHER COST CONSIDERATIONS

This section addresses additional cost considerations that may be incurred by boiler operators and/or regulatory agencies that have not been addressed in Section 8.1. Additional cost impacts are likely in two areas:

- liquid and solid waste disposal, and
- impact of compliance and reporting requirements.

The major liquid and solid waste streams from an uncontrolled boiler are: water softening sludge, condensate blowdown, bottom ash disposal, and coal pile runoff. Bottom ash collection, handling, and disposal costs have been incorporated into the uncontrolled boiler cost estimates. Bottom ash disposal costs were estimated based on a non-hazardous waste classification and RCRA regulations. If boiler wastes are classified as hazardous material in the future, then the disposal costs and overall boiler control costs could increase significantly.

Costs for treating the other three waste streams were not quantitatively evaluated in this study. The costs associated with the disposal problems are highly site-specific, with the following parameters being important:

- Water softening sludge - raw water quality, steam quality, water makeup rate.
- Condensate blowdown - effluent discharge quality requirements, raw water quality, condensate blowdown quantity.
- Coal pile runoff - coal quality, meterological conditions, effluent discharge quality requirements.

However, these costs would be associated with the boiler itself and would not affect the analysis of incremental cost impacts of air pollution controls.

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9. ECONOMIC IMPACT

This chapter presents the background information and methodology for determining the economic impact of a Federal emission standard on new nonfossil fuel fired boilers (NFFB's).

The impact analysis focuses on the economic effects of Control Levels I and II on selected industrial and municipal users. As it is not possible to examine all the industries and municipalities that could exhibit an impact, the users chosen for the analysis are the result of a screening process designed to determine the industries and municipalities that could experience the greatest potential adverse economic effects due to required emission control.

This chapter is divided into two parts. The first section (9.1) profiles the industries and municipalities that will be covered in the economic impact analysis. The second section (9.2) covers the methodology of the analysis as well as the results of the economic impact analysis.

9.1 NFFB USERS

9.1.1 Industrial Users

This section profiles the five manufacturing industries selected for analysis. These industries may experience product cost and profitability impacts and capital availability constraints.

The change in producer price analysis compares the producer price of a product under Control Levels I and II and under the existing State Implementation Plans (SIP's). Similarly, the change in profitability analysis, return on sales and return on assets, measures these indicators under Control Levels I and II and under the existing SIP's. Capital availability constraints can occur when the costs of acquiring funds is so high that a firm considers a project to be uneconomic or financially unattractive.

The following industries are profiled in Section 9.1:

- Wooden furniture manufacturing
- Sawmill lumber products
- Plywood panel products
- Paper and allied products manufacturing
- Raw sugar cane manufacturing.

Each of the industries selected presently burns nonfossil fuels for part or all of its steam requirements. The selection of the waste-fired industries is based on the amount of nonfossil fuel consumed relative to total fuel consumption and the steam intensity of their production processes.

9.1.1.1 Furniture Manufacturing Industry.

9.1.1.1.1 Industry description. The wooden furniture industry segments considered in this description are wood household furniture (SIC 2511) and wood office furniture (SIC 2521). Primary emphasis will be placed on household furniture since it constitutes the major share of wooden furniture produced.

The wooden furniture industry consists of approximately 3,000 casegoods plants out of a total of 5,000 wood and upholstered (with wooden frames) household furniture plants. Of these 3,000 plants, no one plant represents more than three percent of the market share. Approximately 50 percent of production capacity is concentrated in North Carolina, eastern Tennessee, and southeastern Virginia. Tables 9-1a and 9-1b list the lead-

TABLE 9-1a. WOOD HOUSEHOLD FURNITURE MANUFACTURING INDUSTRY[a]

Firm ownership[b]	Location of plants[c]	Sales in 1979 ($\$10^6$)[d] Furniture segment sales	Sales in 1979 ($\$10^6$)[d] Total company sales
American Furniture Co., Inc.	Virginia (9)	71.4	71.4
Armstrong Cork	Mississippi, North Carolina (19), Virginia (2)	201.2	1341.0
Bassett Furniture Industries	Virginia (7), Georgia	272.1	272.1
Bernhardt Furniture Co.	NA[e]	NA	NA
Broyhill Furniture Industries	NA	NA	NA
Burlington Industries	NA	151.9	2676.3
Dixie Furniture Co. Inc.	NA	NA	NA
Drexel Heritage Furnishings, Inc. (Champion International)	NA	NA	3751.0
Ethan Allen (Interco, Inc.)	California, Illinois, Maine, Massachusetts (2), New York (3), North Carolina (4), Ohio, Oklahoma, Pennsylvania (3), Vermont (5), Virginia	160.8	201.1
Henredon	NA		
Lane Co.	NA	NA	158.9
Mohasco	NA	321.3	747.1
Singer Co.	NA	155.9	2599.0

TABLE 9-1a (Continued). WOOD HOUSEHOLD FURNITURE MANUFACTURING INDUSTRY[a]

Firm ownership[b]	Location of plants[c]	Sales in 1979 ($10^6) Furniture segment sales[d]	Total company sales
Sperry & Hutchinson	California, Illinois, Minnesota, New York, North Carolina (6), Tennessee, Texas, Virginia (4)	436.0	821.0
Stanley Furniture (Stanley Interiors Corp.)	NA	NA	NA

[a]Southern Furniture Manufacturer's Association; Securities and Exchange Commission.

[b]Firms listed represent 15-20 percent of total sales. The top 30 companies manufacture $50-$60 million of furniture.

[c]The number in parentheses following State names denotes number of plants.

[d]Sales may include some upholstered and metal furniture, home lighting, carpet, and yarn.

[e]NA denotes not available.

TABLE 9-1b. WOOD OFFICE FURNITURE MANUFACTURING INDUSTRY[a]

Firm ownership	Location of plants[b]	Sales in 1979 ($$10^6$): Furniture segment sales[c]	Sales in 1979 ($$10^6$): Total company sales
Alma Desk	NA[d]	NA	NA
American Furniture Co., Inc.	Virginia (9)		71.4
Baker Furniture Co.	NA	NA	NA
Bassett Furniture Industries	Virginia (7), Georgia	272.1	272.1
Drexel Heritage (Champion International)	NA	NA	3751.0
Ethan Allen (Interco, Inc.)	California, Illinois, Maine, Massachusetts (2), New York (3), North Carolina (4), Ohio, Oklahoma, Pennsylvania (3), Vermont (5), Virginia		
Kimbel International	NA	86.0	211.1
Mohasco	NA	231.3	747.1
Stow & Davis	NA	NA	NA

[a]Business and Institutional Furniture Manufacturer's Association; Securities and Exchange Commission.

[b]The number in parentheses following State names denotes number of plants.

[c]Sales may include some upholstered and metal furniture.

[d]NA denotes not available.

ing wooden furniture companies (both household and office), plant locations, and sales. There are no accurate statistics collected on production of wooden household furniture due to the amount of product differentiation and the fragmentation of the industry as seen in Table 9-2a.[1]

Table 9-2b shows production for all five groups of office furniture. With the exception of modular service units in 1977, production of office furniture has been increasing since 1975. Production figures are lower in 1975 than in the previous year due to the recession's impact on the furniture industry. Production of tables has increased the most between 1975 and 1979. Forecasts estimate the compounded annual real growth rate for the furniture industry from 1980 to 1985 will be 7.8 percent.[2]

9.1.1.1.2 Economic characteristics.

Employment. Casegood furniture production is a labor-intensive process. The maximum employment level per plant for optimal production is 400. Total employment for the household furniture industry was 308,400 in 1979.

Average hourly earnings for production workers in the household furniture industry have increased consistently from $3.30 in 1974 to $4.39 in 1978. For production workers in the office furniture industry, average hourly earnings in 1978 were approximately 15 percent higher than those in the household furniture industry. Even though production workers in the office furniture manufacturing industry receive higher average hourly earnings, they are still low in relation to the average hourly earnings of $6.17 for manufacturing as a whole.

Imports/exports. U.S. household furniture imports were $750 million in 1979, up 21 percent over 1978 imports. During the period 1975 to 1979, imports have been increasing annually by 17.6 percent, indicating a trend toward increased import penetration in the domestic market.[3]

Time series data. The financial analysis of the wooden furniture industry is shown on Table 9-3. The leading manufacturers of wooden furniture had an annual average sales of $787 million. The "average" casegood plant is a much smaller, closely held company with sales of $5 million.

Profits for the industry ranged from a low of $12.5 million in 1975 to a high of $27.9 million in 1976. The impact of the recession on consumer spending can be seen in 1975. This drop is because furniture is a postponable purchase.

TABLE 9-2a. HISTORIC TRENDS OF PRODUCTION FOR WOOD HOUSEHOLD FURNITURE[a]

Indicator	1974	1975	1976	1977	1978	1979
Producer price index[b] (1967 = 100)	136.6	146.3	153.6	162.2	173.5	186.3
Total value of shipments[c] ($\$10^6$)	3381.0	3095.4	3780.1	4154.8	4820.0	5400.0
Value of shipments/plant[c] ($\$10^6$)	NA[d]	NA	NA	NA	1607.0	1800.0

[a]U.S. Department of Commerce. Bureau of Census. Bureau of Labor Statistics. Production figures for 1977 are available but are partial and estimates.

[b]The producer price index is the only valid indicator of price change since there are too many categories and subcategories of furniture to quote.

[c]Dollar amounts are in nominal terms.

[d]NA denotes information not available.

TABLE 9-2b. HISTORIC TRENDS OF PRODUCTION FOR WOOD OFFICE FURNITURE[a]

Indicator	1974	1975	1976	1977	1978	1979
Production (10^3)						
Chairs	1097.2	983.3	1191.6	1355.9	1360.9	NA[c]
Sofa group	74.5	55.2	60.1	88.1	98.4	NA
Desks	519.1	384.9	457.2	644.0	689.6	NA
MSU[b]	242.1	219.8	276.3	204.9	191.4	NA
Table group	263.6	244.6	283.1	566.0	648.8	NA
Producer price index[d] (1967 = 100)	152.4	166.7	173.5	185.9	201.5	221.8
Sales ($\$10^6$)[e]	313.0	292.0	335.0	551.0	687.0	802.0

[a]Business and Institutional Furniture Manufacturer's Association. U.S. Department of Commerce. Bureau of Census. Bureau of Labor Statistics.

[b]MSU denotes modular service units.

[c]NA denotes not available.

[d]The producer price index is the only valid indicator of price change since there are too many categories and subcategories of furniture to quote.

[e]Dollar amounts are in nominal terms.

TABLE 9-3. FINANCIAL ANALYSIS -- WOODEN HOUSEHOLD AND OFFICE FURNITURE MANUFACTURING INDUSTRY[a]
(Nominal Terms)

Financial indicator	1974	1975	1976	1977	1978	1979	Average (1974-1979
Capital expenditures							
Total assets (10^6\$)	NA[b]	536.00	540.30	481.80	444.60	NA	501.70
Capital expenditures/ firm (10^6\$)	NA	23.90	33.70	40.50	43.40	NA	36.40
Capital expenditures/ total assets (%)	NA	4.46	6.23	8.41	9.76	NA	7.26
Profitability							
Net profit after taxes (10^6\$)	NA	12.50	27.90	26.70	27.50	NA	23.70
Return on assets (%)	NA	2.33	5.16	5.54	6.19	NA	4.81
Return on equity (%)	NA	NA	17.46	16.04	15.44	NA	16.31
Return on sales (%)	NA	1.61	3.58	3.48	3.33	NA	3.00
Dividends (\$/share)	1.16	0.67	0.73	0.84	0.98	1.03	0.90
Net earnings before interest and taxes (10^6\$)	NA	36.40	71.40	71.67	81.70	NA	66.29
Capitalization							
Interest on fixed obligations (10^6\$)	NA	12.21	12.23	12.85	13.64	NA	12.73
Coverage ratio	NA	2.98	5.84	5.58	5.99	NA	5.21
Rating on bonds	NA	NA	NA	NA	NA	Baa	Baa
Long-term debt (10^6\$)	NA	65.51	65.89	69.40	66.06	NA	66.72
Stockholders' equity (10^6\$)	NA	NA	159.79	166.43	178.08	NA	168.10
Debt/capitalization (%)	NA	NA	29.90	29.43	27.06	NA	28.41
Debt/equity (%)	NA	NA	41.24	41.70	37.90	NA	39.97

[a]Average/firm estimates for model household and office furniture (Securities and Exchange Commission; EEA estimates).

[b]NA denotes not available.

The net profit margin increased from a low of 1.6 percent in 1975 to a high of 3.6 percent in 1976. Return on total assets has been increasing since 1975 from a low of 2.3 to a high of 6.2 in 1978. Return on total assets and return on net worth were approximately 2.2 percent lower for wood household furniture as compared with wood office furniture.[4] Capital expenditures have remained fairly stable over the 1974 to 1979 period.

Return on equity has been decreasing since 1975, when it was 17.5. Return on equity for wood household furniture was approximately half of that for wood office furniture.

Stockholders' equity has been increasing from $160 million in 1976 to $178 million in 1978. Long-term debt has remained relatively stable. The furniture industry would finance future investments primarily with debt. Ratings on bonds have averaged Baa, which represents a medium grade.

The value of shipments for wood household furniture has been increasing steadily over the past six years, with only one exception in 1975. In 1979, value of shipments for wood household furniture was $5,400 million, a 12 percent increase from the 1978 figures. However value of shipments estimates for 1980 are targeted at $5,238 million, a three percent decrease from last year. This decrease in value of shipments applies to all segments of the household furniture industry, and reflects inflation's effect in reducing real personal income. The percentage decline in furniture shipments is not as great, given the state of the economy, since furniture prices during 1979 rose less than the general price level. Producer prices for all finished goods rose 13 percent during 1979 and furniture rose 6 percent. The typical market share for the average casegood's plant is 0.05 percent.[5]

Five-year projections. The outlook for wooden furniture sales is encouraging. The stimulus to buy during the next five years will be from the large number of persons in the 25-44 age group. In addition, a substantial number of families have two incomes and thus generate more available disposable income. This increase in income will help boost wooden furniture which has traditionally been more expensive than furniture made of other materials. Due to the high cost of fuel, travel has been reduced. Families are spending more on home purchases which will help increase sales of furniture in general.[6]

9.1.1.1.3 Steam use. The most intensive steam requirements are for makeup air and for drying (at the drying/curing kilns and wood finish driers). Makeup air is the process where airborne wood particles, produced from the routers, planers, saws, and sanders in the rough end section, are continually removed from the working environment by a combination of vacuum attachments. These wood particles are then collected for use as fuel. Other steam processes include hot pressing (gluing) and humidifiers.

The furniture industry generates 50 to 100 percent of its energy from wood waste.[7] The leading casegoods manufacturers indicate they use 100 percent waste wood when it is available. An "average" casegood plant burns approximately 907-1814 megagrams (1,000-2,000 tons)/year in its boilers and incinerates the remaining 1,814-2,721 megagrams (2,000-3,000 tons). Wood waste is incinerated or sold since construction of storage bins is expensive. Since purchasing fossil fuels is less expensive than storing wood waste during the winter months, most manufacturers supplement their wood waste with oil and coal from December through February.

Approximately 25 percent of total purchased and captive energy, including electricity, fossil fuel, and waste fuel, is typically used to generate steam.[8] The major manufacturing processes are described below.

- Drying. Lumber is first air-dried, reducing moisture to 14-20 percent, and then kiln-dried to achieve a 6-8 percent moisture content. The drying time varies according to the thickness, species, and initial moisture content of the wood, the location of the yard, and time of year.

- Rough end. The dried lumber is cut into strips of wood and defects removed. The veneers are cut to size and pressed. Lumber panels from rough ending particleboard and hardboard are used for interior layers.

- Machining parts. The blanks and panels are converted to furniture parts with machining operations.

- Assembly and finishing. Furniture parts are assembled and stains, lacquers, and varnishes are applied and dried. Furniture may be rubbed and trimmed. Completed units are packed and sent to the warehouse to await shipping.[9]

9.1.1.2 Lumber Products Industry.

9.1.1.2.1 Industry description. The lumber products industry (SIC 24) is divided into several sub-industries characterized by product. This description of the lumber industry will focus on sawmills and planing mills (primarily sawmills) (SIC 2421), hardwood veneer and plywood (SIC 2435), and softwood veneer and plywood (SIC 2436). These sub-industries are the most significant users of wood waste for their steam needs. For the purposes of this industry description, sawmills will include both soft and hardwood lumber and the panel industry will include both soft and hardwood plywood and veneer.

Sawmills. The sawmill industry consists of approximately 3,133 mills throughout the U.S. producing 37 billion board feet of lumber in 1979. Approximately 80 percent of this total production is softwoods, and the remaining 20 percent is hardwoods.

Sawmills, closely integrated with the paper and allied products industry, are located primarily in the southern and western United States. The largest concentration of sawmills is in Washington (299), Missouri (229), Oregon (221) and North Carolina (211).[10] Table 9-4 lists the leading lumber producers, locations of their mills, and production.

The western States produce 60 percent or more of the softwood output. Of this total western production figure, California, Oregon, and Washington produced more than 70 percent in 1979.

Production of softwoods has increased every year with the exception of 1975 and 1979. Since residential construction is the largest market for softwood, the production decline in these years reflect the decrease in housing starts. More than 58 percent of the sawmills in the western U.S. have been forced to close or curtail production since March 1980.[11]

Growth in the industry over the last ten years has been predominantly in the South, where average sawmill output increased 79 percent from 1966 to 1976. As indicated in Table 9-5, hardwood production did not decline in 1979. Hardwood lumber is primarily of southeastern origin. The principal markets for hardwood lumber are the furniture, materials handling, and flooring industries.

Presently, there is an increase in the consumption of lower grades of hardwood lumber by the furniture industry for "character marked" furniture. Use of these grades saves materials and money by increasing the total lumber supply.[12]

Over the last ten years, there has been a trend toward greater production concentration among large lumber companies. This trend is indi-

TABLE 9-4. SAWMILL AND PLANING MILL INDUSTRY[a]

Firm ownership[b]	Total number of mills	Location of mills[c]	1979 Production: 10^6 board feet lumber (rank)	
Boise Cascade Corp.	14	Idaho (5), Minnesota, North Carolina, Oregon (6), Washington	752	(5)
Champion International Corp.	16	Alabama, California (2), Georgia, Idaho, Louisiana, Montana (4), North Carolina, Oregon (2), South Carolina, Texas, Washington	746	(6)
Crown Zellerbach	8	Louisiana (2), Oregon (3), Washington (3)	819	(4)
Diamond International	3	California (3)	424	(14)
Edward Hines Lumber Co.	9	Arizona, Colorado (2), Idaho, Mississippi, Oregon (2), South Dakota, Wyoming	349	(20)
Georgia-Pacific Corp	36	Alabama (2), Arkansas (5), California, Florida, Georgia (5), Kentucky, Maine, Mississippi (4), North Carolina (6), Oregon (2), South Carolina (4), West Virginia (4)	1,448	(3)

TABLE 9-4 (Continued). SAWMILL AND PLANING MILL INDUSTRY[a]

Firm ownership[b]	Total number of mills	Location of mills[c]	1979 Production: 10^6 board feet lumber (rank)	
ITT Rayonier Inc.	10	Florida (2), Georgia, Washington (2), Alabama, Kentucky, South Carolina (3)	473	(12)
International Paper Co.	15	Arkansas (5), Arizona (3), Georgia, Louisiana, Oregon, Mississippi, South Carolina, Texas (2)	555	(9)
Louisiana-Pacific Corp.	48	Alaska (3), California (19), Florida (3), Idaho (5), Washington (2), Wisconsin (2), Louisiana (2), Michigan (2), Montana, Oregon (5), Texas (4)	2,193	(2)
Mead	10	Alabama, Massachusetts, Michigan (2), Ohio (3), Tennessee, Virginia, Wisconsin	611	(7)
Pope & Talbot Inc.	2	Oregon, Washington	378	(17)
Potlatch Corp.	9	Arizona (2), Idaho (6), Minnesota	587	(8)
Publishers Paper Co.	4	Oregon (4)	403	(15)
Roseburg Lumber Co.	4	California (2), Oregon (2)	402	(16)

TABLE 9-4 (Continued). SAWMILL AND PLANING MILL INDUSTRY[a]

Firm ownership[b]	Total number of mills	Location of mills[c]	1979 Production: 10^6 board feet lumber (rank)	
St. Regis Paper Co.	7	Georgia (2), Maine, Montana, South Dakota, Washington (2)	540	(10)
Sierra Pacific Ind.	8	California (8)	472	(13)
Simpson Timber Co.	2	California (2)	502	(11)
Weyerhaeuser Co.	20	Alabama, Arkansas (3), Mississippi (2), North Carolina (3), Oregon (4), Washington (7)	2,955	(1)
Willamette Industries	9	Arkansas, Louisiana (2), Oregon (6)	355	(19)

[a]Forest Industries Annual Review. Forest Industries Magazine. May 1980. Lockwood's Directory 1980.

[b]Firms listed represent 27 percent of total board feet produced in 1979.

[c]The number in parentheses following the State names denotes number of plants.

TABLE 9-5. HISTORIC TRENDS OF PRODUCTION FOR SAWMILLS AND PLANING MILLS[a]

Indicator	1974	1975	1976	1977	1978	1979
Production (10^6 bd ft/yr)						
Total softwoods	27,193	25,711	29,343	30,987	30,899	29,674
Total hardwoods	6,904	5,872	6,417	6,680	6,758	7,291
Total lumber	34,097	31,583	35,760	37,667	37,657	36,965
Production/mill (10^6 bd ft/yr)	4.32	4.08	4.67	5.03	5.38	11.80
Producer price index (1967 = 100)						
Softwood	211.4	200.6	248.1	297.4	346.0	380.0
Hardwood	189.5	160.3	176.0	200.3	235.8	260.0
Total value of shipments[b] ($\$10^6$)	7,365.2	6,634.8	8,744.2	10,692.1	12,400.0	13,400.0
Value of shipments/mill[b] ($\$10^6$)	0.932	0.856	1.143	1.427	1.771	4.277

[a]Fingertip Facts & Figures, 1980. National Forest Products Association. U.S. Department of Commerce. Bureau of Census. Bureau of Labor Statistics.

[b]Dollar amounts are in nominal terms.

cated in Table 9-5 under production per mill. In 1979, the top 14 lumber companies accounted for 27 percent of all lumber production and an estimated 50 percent of all U.S. plywood and particle board production.

Softwood plywood. In 1979 there were approximately 189 softwood plywood mills and 99 softwood veneer mills throughout the U.S. producing 19.7 billion square feet on a 3/8-inch basis. Since March of 1980, the plywood industry (both soft and hardwood) has fallen to 45 percent of operating capacity with close to 68 percent of its mills closed or running only partially and 20,000 workers idled. The largest concentration of softwood plywood mills is in the West and South. The largest producing States are Oregon (70), Washington (27), and Louisiana (15). Table 9-6 lists leading plywood producers, both softwood and hardwood, their mill locations, and production.

Production of softwood plywood was down in 1979 from 1978 due to the national economic situation. Competition is on the rise from other wood-based panels products such as waferboard, particleboard, fiberboard, hardboard, and composite panels. Many of these competitors are new but experiencing rapid growth. Production of softwood plywood is shown in Table 9-7a.

Hardwood plywood. In 1979 there were approximately 136 hardwood plywood plants and 156 hardwood veneer mills throughout the U.S. producing 1.5 billion square-feet on a 3/8-inch basis. The largest concentration of these mills is in the South. The States with the greatest concentration of mills are North Carolina (52), South Carolina (31), and Wisconsin (24). These three States represent 37 percent of the total number of hardwood plywood mills in the U.S.

The production trend for hardwood plywood and veneer resembles that for softwood plywood and veneer. Except for a two percent decrease in 1979, production has been increasing steadily since 1975. Production of hardwood plywood is shown in Table 9-7b.

9.1.1.2.2 Economic characteristics.

Employment. Average hourly earnings for sawmill and planing mill workers were up to $6.71 in June 1979, compared with $5.83 in December 1978. Earnings for workers in the panel industry are only slightly lower. In mid-1979, there were an estimated 190,000 employees in the lumber industry, an increase of three percent over 1978 figures. Of this total, 165,000 were production workers, a four percent increase over 1978 figures. However, since March 1980, the recession has curtailed production, affecting 61,000 workers. Of this total, 20,000 were plywood workers. In the wood products industry, 28 percent of the employees work in sawmills and planing mills.

Substitutes. The major substitutes for softwood lumber are aluminum and various panels such as plywood. Major substitutes for hardwood also include plywood and other panels. For the plywood industry, substitute products include panels such as particleboard, hardboard, insulation board, medium density fiberboard, thin panel board, waferboard, and composite board.

Imports/exports. U.S. lumber imports, which consist almost entirely of softwoods from Canada, declined more than six percent below the 1978 level in 1979 to 11.2 billion board feet as housing demand slowed. Lumber imports from Canada in 1979 represented 24 percent of total lumber consumption.

U.S. producers, who do not normally sell heavily overseas, used export sales to offset expected declines in the U.S. market. Exports of lumber increased nearly 20 percent during the first half of 1979 and then leveled off during the last half. The total amount of lumber exported in 1979 was estimated at 1.9 billion board feet, an increase of 12 percent over 1978. The U.S. is the second largest lumber-producing country in the world and ranks fourth in lumber exports. These exports represent less than six percent of total domestic production.[13]

Time series data. The financial profile for the leading wood products producers (including lumber and panels) is indicated in Table 9-8. This financial profile will vary only slightly from the profile of the leading paper and allied products companies since the two industries overlap greatly.

Total assets have been increasing steadily since 1974 to $3 billion in 1979. Capital expenditures have also been increasing steadily. Recently, capital spending commitments have jumped to a greater percentage than in the past. In Table 9-8 this percentage for the leading producers is estimated at 20 percent. Estimates show that solid wood producers in general

TABLE 9-6. PLYWOOD AND VENEER INDUSTRY[a]

Firm ownership[b]	Total number of mills	Location of plywood[c] and veneer mills	Production in 1979 (10^6 sq. ft., 3/8" basis)
Boise Cascade Corp.	13	Idaho, Louisiana, North Carolina, Oregon (8), Washington (2)	1,498
Champion International Corp.	12	Alabama, California, Georgia, Louisiana, Montana, Oregon (4), South Carolina, Texas, Washington	1,710
Crown Zellerbach	1	Washington	114
Edward Hines Lumber Co.	1	Oregon	64
Georgia Pacific Corp.	25	Alabama (2), Arizona (2), Florida (5), Georgia (4), Louisiana, Mississippi (3), North Carolina, Oregon (4), South Carolina (2), Virginia	4,623
International Paper Co.	4	Mississippi, Oregon (2), Texas	545[d]
Louisiana-Pacific Corp.	5	California (2), Louisiana, Oregon, Texas	698
Potlatch Corp.	6	Idaho (3)	447[c]
Publishers Paper Co.	1	Washington	95
Roseburg Lumber Co.	4	Oregon	822[c]

TABLE 9-6 (Continued). PLYWOOD AND VENEER INDUSTRY[a]

Firm ownership	Total number of mills	Location of plywood[c] and veneer mills	Production in 1979 (10^6 sq. ft., 3/8" basis)
Southwest Forest Industries	1	Oregon (3)	344[c]
Temple-Eastex, Inc.	2	Texas (2)	474[c]
Weyerhauser Co.	19	Mississippi, North Carolina, Oregon (3), Vermont, Washington,	2,942[c]
Willamette Industries	11	Arizona, Louisiana (3), Kentucky, Oregon (6)	1,192[c]

[a]Panel Review. Forest Industries Magazine. April 1980. Lockwood's Directory 1980.

[b]Firms listed represent 73 percent of total plywood and veneer production.

[c]The number in parentheses following the State names denotes number of plants.

[d]Annual capacity, no production data supplied.

TABLE 9-7a. HISTORIC TRENDS OF PRODUCTION FOR SOFTWOOD VENEER AND PLYWOOD INDUSTRY[a]

Indicator	1974	1975	1976	1977	1978	1979
Production (10^6 sq. ft., 3/8" basis)	15,878	16,050	18,400	19,300	19,760	19,750
Production/mill (10^6 sq. ft., 3/8" basis)	85.99	90.79	101.74	108.49	114.66	111.00
Producer price index - softwood plywood (1967 = 100)	186.8	200.6	247.6	295.8	326.4	322.3
Total value of shipments[b] (\$$10^6$)	2,124	2,244	3,164	3,783	4,214	4,121
Value of shipments/mill[b] (\$$10^6$)	11.9	12.97	17.98	21.74	24.79	23.15

[a]Panel Review, 1980. Forest Industries Magazine. April 1980. U.S. Department of Commerce. Bureau of Census. Bureau of Labor Statistics.

[b]Dollar amounts are in nominal terms.

TABLE 9-7b. HISTORIC TRENDS OF PRODUCTION FOR HARDWOOD VENEER AND PLYWOOD INDUSTRY[a]

Indicator	1974	1975	1976	1977	1978	1979
Production (10^6 sq. ft., 3/8" basis)	1644.0	1280.0	1463.0	1478.0	1481.0	1450.0
Production/mill (10^6 sq. ft., 3/8" basis)	8.84	7.19	8.76	8.69	8.92	8.53
Producer price index - hardwood plywood (1967 = 100)	130.2	119.5	122.5	127.7	140.2	169.1
Total value of shipments[b] ($\$10^6$)	393.6	347.2	416.5	477.4	521.5	NA[c]
Value of shipments/mill[b] ($\$10^6$)	2.12	1.95	2.49	2.81	3.14	NA

[a]Panel Review 1980. Forest Industries Magazine. April 1980. U.S. Department of Commerce. Bureau of Census. Bureau of Labor Statistics.

[b]Dollar amounts are in nominal terms.

[c]NA denotes not available.

TABLE 9-8. FINANCIAL ANALYSIS -- LUMBER PRODUCTS INDUSTRY[a]
(Nominal Terms)

Financial indicator	1974	1975	1976	1977	1978	1979	Average (1974-1979)
Capital expenditures							
Total assets (10^6\$)	1683.40	1830.30	2018.00	2350.70	2505.40	3035.00	2236.70
Capital expenditures/ firm (10^6\$)	330.80	302.10	351.90	395.90	428.30	592.90	400.40
Capital expenditures/ total assets (%)	19.66	16.51	17.44	16.84	17.11	19.54	17.90
Profitability							
Net profit after taxes (10^6\$)	137.77	103.47	139.11	157.31	185.90	250.67	162.37
Return on assets (%)	8.18	5.65	6.89	6.69	7.42	8.26	7.26
Return on equity (%)	16.97	11.51	13.34	13.37	14.32	16.98	14.53
Return on sales (%)	8.43	5.86	6.46	6.48	6.70	7.99	7.01
Dividends (\$/share)	0.91	1.00	1.06	1.17	1.28	1.43	1.14
Net earnings before interest and taxes (10^6\$)	262.60	210.19	242.30	282.83	351.19	390.69	298.97
Capitalization							
Interest on fixed obligations (10^6\$)	36.40	43.52	43.26	45.52	47.67	55.67	45.34
Coverage ratio	7.21	4.83	5.60	6.21	7.37	7.02	6.40
Rating on bonds	NA[b]	NA	NA	Aa/Baa	Aa/Baa	Aa/Baa	Aa/Baa
Long-term debt (10^6\$)	507.96	559.51	585.92	575.32	632.77	689.11	591.77
Stockholders' equity (10^6\$)	812.06	899.01	1043.00	1176.59	1298.46	1475.93	1117.51
Debt/capitalization (%)	38.48	38.36	35.97	32.84	32.77	31.83	34.62
Debt/equity (%)	62.55	62.24	56.18	48.90	48.73	46.69	52.95

[a]Average/firm estimates for model firms (Securities and Exchange Commission; EEA estimates).

[b]NA denotes not available.

increased capital spending by over 65 percent from 1978. The South aggregated the biggest regional share of these expenditures.[14]

Profits for the industry range from a low of $103 million in 1975 to a high of $251 million in 1979. The net profit margin was highest in 1974 at 8.4 percent, averaging 7.0 percent for the six years. Return on assets averaged 7.3 percent and return on equity averaged 14.5 percent.

The debt-to-equity ratio has been decreasing since 1974, indicating these companies would probably finance new investments with debt. An average of several bond ratings ranged between Aa and Baa, representing an above average rating of credit worth.

<u>Five-year projections (sawmills)</u>. Lumber output during the next five years will be largely influenced by the general economy and trend in construction, especially residential. Construction accounts for 80 percent of lumber and 42 percent of softwood plywood. In October 1979, the Federal Reserve Board tightened credit which accelerated the slide that was already occurring in construction activity. Housing starts in 1979 declined to 1.75 million, down from more than 2 million in 1978, resulting in real production declines of 1.2 percent in lumber and 4 percent in softwood plywood production.[15] However, the value of shipments for lumber increased about 9 percent in 1979 because prices remained high.

The number of housing starts is estimated to average slightly less than two million units through 1984. Other types of construction should realize a demand similar to housing.

Two major factors that will influence the lumber industry are competition for raw material supplies and competition in the market with other building materials. The South is estimated to produce one-half of the nation's future wood products. Currently the South supplies slightly over 34 percent of the nation's wood, so its share is expected to increase substantially.

<u>Five-year projections (panel industry)</u>. The outlook for wood-based structural panels is favorable through the mid-1980's. There should be a shift to consumption of reconstituted board, which primarily consists of particleboard, hardboard and insulation board, from the traditional softwood plywood markets. However, the softwood plywood manufacturers will not suffer greatly since they produce most of the reconstituted board.

Capacity in 1980 for softwood plywood should reach over 22 billion square feet. Most new capital expenditures will be directed towards composite wood panels. This segment of the industry should increase to capture 18 percent of the wood panel market by 1984. The price of softwood plywood is projected to increase about 10 percent per year until 1984 due to rising raw material costs.[16] Forecasts estimate the compounded annual real growth rate for the lumber products industry from 1980-1985 will be 5.3 percent.[17]

9.1.1.2.3 Steam use. As indicated in Table 9-9, over 70 percent of the leading companies' total fuel consumption is from wood waste. These companies accounted for 27 percent of all lumber production.

Most of the steam required in a sawmill is for drying, which consumes approximately 75 to 85 percent of total steam required.[18] The major manufacturing processes for sawmills are described below.

- Debarking. Logs in raw form are debarked and cut to various lengths, the maximum of which is 20 feet.
- Sawing. In this process the log is cut further by the head saw which is a carriage powered by a steam cylinder. The log is turned, weighted, edged, and trimmed to desired lengths. The result is a green end, which is an undried piece of lumber.
- Drying. Approximately 65 percent of all cut lumber is kiln dried. The kiln is heated by steam or other means. Energy required for softwood drying range from 1,055 kJ (1,000 Btu)/foot of Douglas fir to 3,690 kJ (3,500 Btu)/board foot of pine, depending on the cut and moisture of the wood.
- Planing. Dried lumber moves to a planer where it is finished and smoothed. Lumber end products are either rough or dressed (planed) boards and chips.[19]

Manufacturing plywood involves the assembly of layers of veneer joined together by an adhesive. Of the major plywood manufacturing processes listed below, log conditioning is the most steam-intensive. Approximately 25 percent of the total purchased and captive energy is used to generate steam.

- Log conditioning. Logs are heated to improve the cutting properties of wood. Heating may be accomplished by directing steam onto the logs in a steam vat or by heating the logs in a hot water vat, heated by steam.

- Veneer cutting. More than 90 percent of all veneer is rotary cut. The log is turned against a knife and a thin sheet of veneer is pulled from the log.

- Veneer drying. Veneers are usually dried to a moisture content of less than 10 percent to make them suitable for gluing. The majority of high temperature veneer dryers (above 212°F) use steam or forced hot air. Plywood drying and glue heating consume about 25×10^3 kJ/square meter (2.2×10^6 Btu/MSF).

- Gluing and pressing. One of three main types of glues is applied to the veneers, depending on the end use of the plywood (indoor or outdoor). Glues may be applied by a spreader, roller, or sprayer. The veneer is then pressed to ensure proper alignment.

- Finishing. Finishing may include redrying, trimming, sanding, sorting, molding, and storing.[20]

9.1.1.3 Paper and Allied Products Manufacturing Industry.

9.1.1.3.1 Industry description. The segments of the paper and allied products industry (SIC 26) considered in this industry description are pulp mills (2611), paper mills (SIC 2621), and paperboard mills (SIC 2631).

The paper and allied industries consists of 917 establishments throughout the United States, producing 61.5 million tons of paper and paperboard in 1979. There are a total of 405 companies operating 725 paper and/or paperboard mills and 426 pulp mills in the United States. Pulp, paper, and board mills are primarily located in the Northeast (231), South (185), and North Central (176) States.[21]

Table 9-10 shows the largest producers of paper and allied products the location of their plants, and their sales. The sales of these top 19 companies account for $28 billion of paper-related sales. This is approximately 52 percent of total paper sales in 1979. Production figures for paper and allied products are shown in Table 9-11.[22]

Economies of scale have encouraged the growth of integrated mills, especially in the South and the West. The elimination of drying and re-pulping of pulp in integrated mills helps to reduce the costs of energy capital, labor, and transportation. About 75 percent of the pulp used by paper mills and 97 percent of the pulp used by paperboard mills were produced at the same location in 1975.[23]

Pulp mills. Pulp mills follow the economic trends for the paper and paperboard and related products industry. Total U.S. production capacity

TABLE 9-9. ENERGY CONSUMPTION OF MAJOR LUMBER PRODUCERS IN 1978-79[a]

Sources	Units	1978 Estimated fuel use	1978 10^{12} KJ (10^{12} Btu)	1978 % of total	1979 Estimated fuel use	1979 10^{12} KJ (10^{12} Btu)	1979 % of total
Purchased electricity	10^6 kWh	4899.7	17.6 (16.7)	10.0	4852.6	17.6 (16.7)	10.0
Purchased steam	10^6 kg (10^6 lbs)	884.8 (1950.9)	2.5 (2.3)	1.4	972.3 (2,143.8)	2.7 (2.6)	1.5
Purchased fossil fuel	---	---	34.3 (32.5)	19.7	---	32.2 (30.5)	18.3
Total purchased fossil fuel and energy			54.4 (51.5)	31.1		52.5 (49.7)	29.8
Self-generated hogged fuel, wood and bark	10^3 Mg (10^3 tons)	9,364.2 (10,324.4)	114.7 (108.7)	65.5	9,459.3 (10,428.9)	116.6 (110.5)	66.1
Purchased hogged fuel, wood and bark	10^3 Mg (10^3 tons)	384.7 (424.1)	3.7 (3.5)	2.1	555.2 (612.1)	5.2 (4.9)	2.9
Other self-generated and waste fuels	---	---	2.4 (2.3)	1.4	---	2.2 (2.0)	1.2
Total hogged fuel, wood, and waste fuels			120.7 (114.4)	68.9		123.9 (117.4)	70.2
Total all energy			175.1 (166.0)	100.0		176.4 (167.2)	100.0

[a]National Forest Products Association Report to DOE on Energy Consumption by SIC 24. June 30, 1980. The 14 companies represented in this table account for 27 percent of all lumber production and an estimated 50 percent of all U.S. plywood and particle board production.

TABLE 9-10. PAPER AND ALLIED PRODUCTS INDUSTRY[a,b]

Firm ownership	Number of mills	Location of mills[c]	Sales in 1979 ($$10^6$) Paper	Sales in 1979 ($$10^6$) (Rank)	Total company sales	Percent of total company sales
Boise Cascade Corp.	13	Massachusetts, Maine, Minnesota, New York (2), Oregon (3), Vermont, Washington (3), Louisiana	1,652	(8)	2,916	56
Champion International	7	Alabama, Illinois, Ohio, Oregon, South Carolina, North Carolina, Texas	1,870	(5)	3,751	50
Container Corp. of America (Mobil Oil)	13	Alabama, California (2), Delaware, Florida, Indiana (2), Ohio (2), Pennsylvania, Tennessee, Washington, Illinois	1,462	(10)	44,721	3
Continental Group (Continental Forest Industries)	3	Georgia (2), Louisiana, Virginia	1,043	(15)	4,370	24
Crown-Zellerbach	15	California (3), Louisiana (2), New York (2), Ohio, Oregon (3) Washington (4)	1,500	(9)	2,807	53
Diamond International	12	California, Illinois, Maine, Massachusetts (2), Mississippi, New York (2), Ohio (2), New Hampshire (2)	663	(19)	1,284	52

TABLE 9-10 (Continued). PAPER AND ALLIED PRODUCTS INDUSTRY[a,b]

Firm ownership	Number of mills	Location of mills[c]	Sales in 1979 ($$10^6$) Paper	Sales in 1979 ($$10^6$) (Rank)	Total company sales	Percent of total company sales
Georgia-Pacific	22	Arizona, Connecticut, Florida, Georgia, Illinois, Indiana, Louisiana, Maine, Michigan, New Jersey, New York (3), North Carolina, Ohio, Oklahoma, Oregon (2), Pennsylvania, Vermont, Virginia, Washington, Wisconsin	1,269	(12)	5,207	24
Great Northern Nekoosa Corp.	7	Maine (2), Arkansas, Wisconsin (3), Georgia	832	(16)	1,158	71
Hammermill Paper Co.	4	Alabama, Pennsylvania (3)	927	(14)	1,077	86
International Paper Co.	14	Alabama (2), Arkansas (2) Louisiana, Maine, Mississippi (3), New York (2), Oregon, South Carolina, Texas	3,694	(1)	4,534	81
Kimberly-Clark	12	Alabama, California, Connecticut, Maine, Michigan, New Jersey (2), Pennsylvania, South Carolina, Tennessee, Wisconsin	2,028	(4)	2,218	91
Mead Corp.	7	Alabama, Massachusetts, Michigan, Ohio (2), Tennessee, Virginia	1,774	(7)	2,570	70

TABLE 9-10 (Continued). PAPER AND ALLIED PRODUCTS INDUSTRY[a,b]

Firm ownership	Number of mills	Location of mills[c]	Sales in 1979 ($\$10^6$) Paper	(Rank)	Total company sales	Percent of total company sales
Owens Illinois, Inc.	5	Georgia, Maine, Texas, Virginia, Wisconsin	684	(18)	3,504	20
St. Regis	14	Florida (3), Maine, Michigan, Minnesota, Mississippi, New York (2), Ohio (2), Pennsylvania, Texas, Washington	2,085	(3)	2,499	83
Scott Paper	9	Alabama, Maine (2), Michigan, New York, Pennsylvania, Washington, Wisconsin (2)	1,811	(6)	1,908	95
Time, Inc. (Inland/Temple Eastex)	5	California, Indiana, Tennessee, Texas (2)	717	(17)	2,504	27
Union Camp Corp.	5	Alabama, Georgia, Michigan, New Jersey, Virginia	1,277	(11)	1,389	92
Westvaco	5	Kentucky, Maryland, Pennsylvania, South Carolina, Virginia	1,087	(13)	1,200	89
Weyerhaeuser Co.	15	Arkansas, North Carolina (3), Oklahoma (2), Oregon (2), Pennsylvania, Washington (4), Wisconsin (2)	2,385	(2)	4,423	54

[a] Lockwood's Directory, 1980; Post's Directory 1980; Miller Freeman Publications; Federal Trade Commission.

[b] Only domestically owned firms are listed. Firms listed represent 52 percent of total paper sales.

[c] Numbers in parentheses following the State names denotes number of plants.

TABLE 9-11. HISTORIC TRENDS OF PRODUCTION FOR PAPER AND ALLIED PRODUCTS[a]

Indicator	1974	1975	1976	1977	1978	1979
Production (10^3 Mg/yr (10^3 st/yr))						
Paper	24,194	21,152	24,138	24,935	25,151	27,076
	(26,674)	(23,320)	(26,612)	(27,491)	(27,729)	(29,851)
Board	25,412	22,179	25,252	26,056	26,053	NA[b]
	(28,017)	(24,452)	(27,840)	(28,727)	(28,723)	(NA)
Paper and board	49,606	43,331	49,390	50,991	51,204	NA
	(54,691)	(47,772)	(54,452)	(56,218)	(56,452)	(NA)
Pulp	43,854	39,078	43,284	45,355	45,782	45,118
	(48,349)	(43,084)	(47,721)	(50,004)	(50,475)	(49,743)
Total	93,460	82,409	92,674	96,346	96,986	NA
	(103,040)	(90,856)	(102,173)	(106,222)	(106,927)	(NA)
Production/mill (10^3 Mg/yr (10^3 st/yr))	118.00	54.00	118.00	125.00	127.00	NA
	(130.26)	(59.38)	(129.50)	(137.24)	(139.77)	(NA)
Average price[c] ($/$10^3$ Mg/yr ($/$10^3$ st/yr)	0.15	0.16	0.17	0.17	0.20	NA
	(0.16)	(0.18)	(0.19)	(0.19)	(0.22)	(NA)
Producer price index (1967 = 100)						
Paper and allied products	151.70	170.40	179.40	186.40	195.60	219.00
Wood pulp	217.80	283.40	286.00	281.10	266.50	314.30
Paper	148.60	175.90	182.30	194.30	206.10	229.60
Paper board	152.20	170.30	176.00	176.20	179.60	202.10

TABLE 9-11 (Continued). HISTORIC TRENDS OF PRODUCTION FOR PAPER AND ALLIED PRODUCTS

Indicator	1974	1975	1976	1977	1978	1979
Total value of shipments[c] ($\$10^6$)						
Paper and board	15,079	14,621	17,570	18,579	21,784	23,984
Pulp	1,525	1,630	2,055	2,071	2,200	2,644
Total	16,604	16,251	19,625	20,650	23,984	26,628
Value of shipments/mill[c] ($\$10^6$)	20.99	10.62	24.87	26.68	31.35	35.04

[a]Statistics of Paper & Paperboard 1979, American Paper Institute. Lockwood's Directory, 1979. U.S. Department of Commerce. Bureau of Census. Bureau of Labor Statistics.

[b]NA denotes not available.

[c]Dollar amounts in nominal terms.

or pulp mills was 6.2 million short tons for pulp mills in 1979 with an annual production figure of 5.7 million short tons. In 1980, annual production capacity is estimated to be 6.5 million short tons with production at 5.8 million short tons. Capacity utilization in the pulp mills has ranged from 79.5 percent in 1975 to 94.3 percent in 1978.

Growth in the pulp industry, as with lumber, has occurred primarily in the South where land has been converted from cotton to timber. Half of pulp production is in the South, with the remaining half in the Northeast, North Central, and Pacific regions.

The increased scale of pulp mill production capacity (indicated by the decrease in number of establishments with a simultaneous increase in capacity), together with labor-saving and cost-saving efficiencies, has enhanced productivity in U.S. pulp mills.

Paper mills. Paper and board mill operating rates averaged 94.5 percent of rated capacity in 1979. Total paper and board capacity is estimated to be 74 million tons in 1980 and 75 million tons in 1981. Total paper and board capacity has ranged from 66 million tons in 1974 to 72 million tons in 1979, with only increasing capacity throughout those years.[24]

9.1.1.3.2 Economic characteristics.

Employment. Total employment within the pulp mills is expected to grow less than one percent in 1980. Total employment in this highly automated industry will remain within the 16,000-plus range. The hourly wage for pulp mill production workers in 1979 averaged close to $8.18 an hour.

Total employment in the paper and board industry was estimated at 211,000 in 1979. The average hourly earnings for production workers in paperboard mills has been about three percent higher than that of the paper and pulp mill production worker over the last six years.

Paper and paperboard were faced in 1978 by more than 50 strikes. Most strike activity was centered in the Northwest. Provisions for cost-of-living adjustments represented a significant departure from the standard paper industry settlements and introduced an additional long-term cost to the industry's cost structure.

Substitutes. The major substitutes for domestic paper and allied products are imports, some types of wood panels (for paperboard), and waste paper for virgin pulp grades.

Imports/exports (pulp). The U.S. has always been a large net importer of pulp. In 1979, the amount of imports as a percent of apparent consumption was 59.5 percent. Pulp imports for 1980 are estimated at 4,013,605 megagrams (4,425,000 tons) exceeding exports of 2,752,835 megagrams (3,035,000 tons) by 46 percent.

Imports/exports (paper and board). In 1980, import volume is expected to drop 10 percent to 7,256,238 megagrams (8,000,000 tons). Imports as a percent of apparent consumption were 11 percent in 1979. Imports should drop in 1980 due to expanded U.S. capacity in printing papers. The value of imports should hold at $2.8 billion because of price increases.

Paper and board exports should climb by 10 percent, reaching $1.4 billion in value and 3 million megagrams (3.3 million tons) in volume in 1980. The climb in exports is a result of producers seeking to maintain favorable operating rates by offsetting slowed domestic demand. The decline in the monetary exchange rate of the dollar has also improved the competitive position of U.S. paper and board producers in foreign markets, especially in Japan.[25]

Time series data. Despite the slowing of the general economy, paper and board should post new gains in 1980. The paper industry has had record sales and earning throughout most of the 1970's. Sales have climbed from an average of $1.9 billion for the top 10 companies in 1974 to an average of $3.1 billion in 1979. The only exception was a slight dip in 1975. Value of shipments from the paperboard establishments should be about 7 percent above the estimated figure for 1979.

The financial profile of the leading paper and allied products companies is shown on Table 9-12 from 1974 to 1979. Profits range from a high of $260 million in 1979 to a low of $103 million in 1975, reflecting the industry's sensitivity to the change in GNP. Profits were high in 1979 despite labor strikes.

Total assets have increased steadily since 1974. Capital expenditures have been fairly constant between 1974 and 1979, showing an increase in 1979. The paper industry had estimated increasing capital outlays by 40 percent in 1979, which is high compared to the 13 percent annual average increase for all business.

TABLE 9-12. FINANCIAL ANALYSIS -- PAPER AND ALLIED PRODUCTS INDUSTRY[a]
(Nominal terms)

Financial indicator	1974	1975	1976	1977	1978	1979	Average (1974-1979)
Capital expenditures							
Total assets (10^6 $)	1702.80	1858.60	2053.10	2293.90	2488.30	2793.60	2198.40
Capital expenditures/ firm (10^6 $)	311.40	301.50	344.70	370.50	390.30	493.50	368.60
Capital expenditures/ total assets (%)	18.29	16.22	16.79	16.15	15.69	17.67	16.77
Profitability							
Net profits after taxes (10^6 $)	135.60	102.88	136.88	147.01	176.52	260.46	159.89
Return on assets (%)	7.96	5.54	6.67	6.41	7.09	9.32	7.27
Return on equity (%)	15.88	11.00	12.85	12.39	13.75	17.73	14.12
Return on sales (%)	7.04	5.59	6.24	6.08	6.43	8.49	6.76
Dividends ($/share)	1.07	1.19	1.26	1.38	1.50	1.71	1.35
Net earnings before interest and taxes (10^6 $)	259.37	208.39	255.29	277.07	342.02	390.93	288.85
Capitalization							
Interest on fixed obligations (10^6 $)	33.47	39.59	41.97	46.83	48.97	50.62	43.57
Coverage ratio	7.75	5.26	6.08	5.92	6.98	7.72	6.63
Rating on bonds	NA[b]	NA	NA	NA	Aa/Baa	Aa/Baa	Aa/Baa
Long-term debt (10^6 $)	467.70	525.83	545.04	605.88	626.55	649.86	570.14
Stockholders' equity (10^6 $)	854.11	935.68	1064.98	1186.57	1284.14	1469.44	1132.49
Debt/capitalization (%)	35.38	35.98	33.85	33.80	32.79	30.66	33.48
Debt/equity (%)	54.76	56.20	51.18	51.06	48.79	44.23	50.34

[a]Average/firm estimates for model firms (Securities and Exchange Commission; EEA estimates).

[b]NA denotes not available.

From 1974 to 1977, the net profit margin ranged from about 5.6 percent to 8.5 percent. Return on total assets averaged 7.3 percent and return on equity averaged 14.1 percent.

An average of several paper companies' bond ratings was Aa to Baa, which represents an above average rating of credit worth.

Five-year projections (pulp). Market pulp production, domestic demand and shipments, and export shipments should maintain their proportional positions in relation to total U.S. pulp production. U.S. pulp production is estimated to reach 5,986,395 megagrams (6,600,000 tons) or 12 percent of total pulp production in 1984, compared with the current 10 to 11 percent.

Five-year projections (paper and board). The U.S. paper and board industry has a large domestic market and the potential to increase its share in the world markets.

An improved capital investment framework, accompanied by advancing technology, will provide this industry with increased growth in the future. Forecasts estimate a 4.8 percent compounded annual real growth rate for the paper and allied products industry from 1980-1985.[26]

9.1.1.3.3 Steam use. As indicated in Table 9-13, total self-generated and waste fuels are 47.3 percent of total energy consumed by the paper and allied industry in 1979. Of this, 9.2 percent is hogged and bark fuel. Approximately two thirds of total purchased and captive energy, including electricity, fossil fuel, and waste fuel, are typically used to generate steam.

Pulp is produced from wood by mechanical or chemical means. The process described below depicts the Kraft process, which is a chemical process. Because chemical pulping generates 68 percent of total paper production and because the Kraft process accounts for 90 percent of all chemical pulping, this method represents a significant portion of the industry. Pulping consumes 17 percent of the total steam requirements for producing paper.[27]

- Debarking and chipping. Bark is removed from the logs in a steel drum or hydraulic barker. These logs are then reduced to chips by a rotating knife device to help improve the rate of cooking liquor penetration during pulping.

- Digesting. Wood chips are cooked under pressure in a digestor to dissolve lignin and release cellulose. Spent pulping liquor is recovered in this process.

TABLE 9-13. ENERGY CONSUMPTION IN THE PULP, PAPER AND PAPERBOARD INDUSTRY IN 1978-79[a]

Sources	Units	1978 Estimated fuel use	1978 10^{12} KJ (10^{12} Btu)	1978 % of total	1979 Estimated fuel use	1979 10^{12} KJ (10^{12} Btu)	1979 % of total
Purchased electricity	10^6 kWh	35,344.0	126.8 (120.2)	5.5	38,387.3	137.7 (130.5)	5.9
Purchased steam	10^6 kg (10^6 lbs)	7,302.5 (16,102.0)	20.4 (19.3)	0.9	5,994.4 (13,217.6)	16.7 (15.9)	0.7
Purchased fossil fuel	---	---	1,059.3 (1,004.1)	46.8	---	1,061.9 (1,006.5)	46.1
Total purchased fossil fuel and energy			1,206.4 (1,143.5)	53.2		1,216.3 (1,152.9)	52.7
Hogged fuel (50% moisture content)	10^3 Mg (10^3 tons)	10,599.8 (11,686.7)	101.1 (95.8)	4.4	12,048.2 (13,283.6)	(108.9)	114.9 4.9
Bark (50% moisture content)	10^3 Mg (10^3 tons)	9,679.0 (10,671.4)	100.2 (95.0)	4.3	9,651.1 (10,640.7)	99.9 (94.7)	4.3
Spent liquor (solids)	10^3 Mg (10^3 tons)	59,478.2 (65,576.8)	860.1 (815.3)	37.2	60,871.3 (67,112.8)	878.0 (832.2)	37.3
Other self-generated energy	---	---	20.0 (19.0)	0.9	---	19.4 (18.4)	0.8
Total self-generated and waste fuels			1,081.3 (1,025.0)	46.8		1,112.2 (1,054.2)	47.3
Total all energy			2,329.0 (2,207.1)	100.0		2,328.5 (2,207.1)	100.0

[a]American Paper Institute - Raw Materials and Energy Division. Based on sample 86 percent of total dried pulp, paper, and paperboard production for 1979, 83 percent for 1978. Determined by using "Total energy" + "Energy sold" as denominator.

- Bleaching. After screening, pulp may be bleached. Bleaching produces a whiter pulp stock by removing residual lignins. Most paper is bleached, most paperboard is not, or only partially. Bleaching consumes 33 percent of total paper-making steam requirements. Pulp goes from the pulp mill to the paper-making mill in the form of slurry whenever possible.

If the pulp continues to be made into a final paper product, the following steps occur. Actual paper making consumes 40 percent of total steam requirements.

- Refining. Pulp is mechanically pounded in a "hollander" to increase the strength of the paper and lower the porosity. The pulp is then suspended in water and fed to a paper machine.

- Forming. Paper is formed with a Foudrinier or cylinder machine. The slurry is discharged into a "head box" onto a screen that moves between two rolls.

- Pressing. Presses remove water by mechanical action. At this stage the water content is reduced to 65-70 percent.

- Drying. Drying the wet sheet consumes one-half of the heat requirements for paper making. The sheet is passed between steam-heated cylinders.

- Finishing. Dried paper may be further processed by embossing, impregnating, laminating, and coating. Paper surfaces can be passed between rolls under high pressure to improve shine and density.[28]

9.1.1.4 Raw Sugar Cane Manufacturing Industry.

9.1.1.4.1 Industry description. The raw sugar cane manufacturing industry (SIC 2061) consists of 44 companies with 47 mills in the domestic U.S. and seven mills in Puerto Rico, owned or leased by a government agency. Sugar cane is milled in four States and one territory: Louisiana leads in the number of mills (25), followed by Hawaii (14), Florida (7), Puerto Rico (7), and Texas (1). Table 9-14 lists the sugar milling companies in the U.S., their mill locations, and production. There are predominantly four types of mill operations in the sugar cane industry: closely held companies (usually family operations), large diversified corporations, government owned corporations, and farmer's cooperatives.[29]

U.S. raw sugar production for 1979 was close to 2,780,000 megagrams (3,065,000 tons); U.S. per capita consumption of sugar was 199.54 kilograms (90.7 pounds) refined. Production between 1974-1979 has ranged from

TABLE 9-14. RAW CANE SUGAR MANUFACTURING INDUSTRY[a]

Firm ownership[b]	Number of mills	Location of mills	Metric tons ground/day[c] in 1979
Aguirre	1	Puerto Rico	7,500
Alma Plantation, Ltd.	1	Louisiana	2,400
Atlantic Sugar Assoc.	1	Florida	7,200
Beaux Bridge Coop., Inc.	1	Louisiana	2,400
Caire & Graugnard	1	Louisiana	2,000
Cajun Sugar Coop., Inc.	1	Louisiana	6,000
Caldwell Sugars Coop, Inc.	1	Louisiana	5,000
Cambalache	1	Puerto Rico	4,000
Coloso	1	Puerto Rico	6,000
Cora-Texas Manuf. Co., Inc.	1	Louisiana	3,500
Davies Hamakua Sugar Co.	1	Hawaii	4,300
Davies Honokaa Sugar Co. (Theo H. Davies & Co.)	1	Hawaii	4,300
Dugas & LeBlanc, Ltd.	1	Louisiana	4,200
Evan Hall Sugar Corp.	1	Louisiana	5,000
Glenwood Coop., Inc.	1	Louisiana	4,200

TABLE 9-14 (Continued). RAW CANE SUGAR MANUFACTURING INDUSTRY[a]

Firm ownership[b]	Number of mills	Location of mills	Metric tons ground/day[c] in 1979
Guanica	1	Puerto Rico	8,000
Gulf & Western Food Products Co.	1	Florida	18,000
Harry L. Laws & Co., Inc.	1	Louisiana	4,200
Hawaiian Commercial & Sugar Co.	2	Hawaii	9,500
Helvetia Sugar Coop., Inc.	1	Louisiana	3,000
Hilo Coast Processing Co. (Papaikou factory closed in 1980) (IU International Corp.)	2	Hawaii	6,950
Iberia Sugar Cooperative, Inc.	1	Louisiana	4,250
Jeanerette Sugar Co., Inc.	1	Louisiana	2,720
Ka'u Sugar Co., Inc. (IU International Corp.)	1	Hawaii	2,800
Kekaha Sugar Co. (Amfac, Inc.)	1	Hawaii	3,000
Lafourche Sugar Co.	1	Louisiana	6,500
M.A. Partout & Son, Ltd.	1	Louisiana	5,000
Meeker Sugar Coop., Inc.	1	Louisiana	3,500

TABLE 9-14 (Continued). RAW CANE SUGAR MANUFACTURING INDUSTRY[a]

Firm ownership[b]	Number of mills	Location of mills	Metric tons ground/day[c] in 1979
Mercedita	1	Puerto Rico	4,500
McBryde Sugar Co., Ltd. (Alexander & Baldwin)	1	Hawaii	2,600
Oahu Sugar Co., Ltd. (Amfac, Inc.)	1	Hawaii	3,200
Olokele Sugar Co., Ltd. (IU International)	1	Hawaii	2,700
Osceola Farm Co.	1	Florida	7,200
Pioneer Mill Co. (Amfac, Inc.)	1	Hawaii	2,700
Plata	1	Puerto Rico	5,000
Puna Sugar Co. (Amfac, Inc.)	1	Hawaii	4,500
Rio Grande Valley Sugar Growers, Inc.	1	Texas	8,500
Roig	1	Puerto Rico	4,500
St. James Sugar Coop., Inc.	1	Louisiana	5,000
St. Martin Sugar Coop.	1	Louisiana	4,000

TABLE 9-14 (Continued). RAW CANE SUGAR MANUFACTURING INDUSTRY[a]

Firm ownership[b]	Number of mills	Location of mills	Metric tons ground/day[c] in 1979
St. Mary Sugar Coop., Inc.	1	Louisiana	3,500
Savoie Industries	1	Louisiana	3,800
Smithfield Sugar Coop., Inc.	1	Louisiana	3,500
South Coast Sugars, Inc.	1	Louisiana	4,535
Sterling Sugars Inc.	1	Louisiana	7,500
Sugar Cane Growers Coop. of Florida	1	Florida	18,000
Supreme Sugar Co, Inc. (Archer Daniels Midland Co.)	1	Louisiana	4,000
Talisman Sugar Corp.	1	Florida	7,200
The Lihue Sugar Corp.	1	Hawaii	3,800
United States Sugar Corp.	2	Florida	24,400
Waialua Sugar Co., Inc. (Castle & Cooke, Inc.)	1	Hawaii	5,000
Wailuku Sugar Co. (Closed in 1980) (IU International Corp.)			

[a]Sugar y Azucar Yearbook, 1980.

[b]U.S. Mainland and Hawaii centrifugal sugar factories grinding more than 500 tons of cane per day.

[c]Represents input per day.

2,806,000 megagrams (3,094,000 tons) in 1974 to 3,209,000 megagrams (3,538,000 tons) in 1975. Approximately 37 percent of 1979 production was from Florida, 36 percent from Hawaii, 18 percent from Louisiana, 6 percent from Puerto Rico, and 3 percent from Texas.[30] Both Hawaii's and Florida's production increased in 1978 and 1979, while Texas', Louisiana's, and Puerto Rico's production decreased. Table 9-15 lists production statistics.[31]

Florida has two cooperatives and five privately owned companies located in the southeastern Lake Okeechobee area. The harvesting season for sugar cane in Florida averages five months, from November to April. The majority of the raw sugar produced is sent to refineries, with only 20-25 percent of total production refined locally. Florida currently is experiencing dramatic growth in its sugar cane industry, although it will become increasingly expensive for the Florida industry to expand its capacity in the future, since the soils surrounding the lake region are not as fertile.[32]

Hawaii is unique among sugar cane growing areas because it has a year-round growing and harvesting season and the age of the sugar cane crop at harvest averages two years. Hawaiian sugar mills are similar in capacity size to the Louisiana mills; however they are more similar to the Florida industry in terms of efficiency in production.

Louisiana sugar cane production has been characterized by a rapid decline in the number of farms producing cane and an increase in the output of the remaining farms on which the crop is grown. Most of the sugar cane millers still operate small-scale farms and cannot realize the economies of scale that the other three sugar-producing States achieve. Louisiana has a shorter harvest season of 2.5 to 3 months. Due to freezing weather, Louisiana has less cane yields per acre and sugar yields per megagram of cane. Sugar mills tend to be old and relatively inefficient.[33]

The Texas sugar industry harvested its first crop in 1973. There is one grower-owned raw sugar mill in Texas, similar in size and efficiency to the Florida mills. In 1979, Texas' seventh harvest, the cooperative established a new record of a 10.80 yield percent cane of 773,000 metric tons net cane in a harvest season of 5.5 months.[34]

All seven Puerto Rico sugar mills are owned or leased by the Sugar Corporation of Puerto Rico, an agency of the government of the Commonwealth of Puerto Rico. The industry is characterized by small-scale poducers. Increasing wage rates, together with increasing industrialization and urbanization, have been credited for the decline in sugar production over the last 28 years.

9.1.1.4.2 Economic characteristics.

Employment. Production workers in 1973 totaled 5,600 in 83 mills, with total employment at 7,100. Industry sources indicate that the number of employees averages about 100/plant. Based on this estimate for the 54 U.S. cane mills in 1979, total employees averaged 5,400 in 1979.[35]

Annual hourly earnings for production workers in the sugar and confectionary products industry averaged $5.62 in 1978.[36]

Substitutes. The major substitutes for cane sugar are beet sugar, corn syrup, imported cane sugar, molasses, and brown sugar.[37]

Imports/exports. Raw sugar, produced from sugar cane, is produced in some 38 countries. Imported raw sugar receipts in 1979 were 4,444,000 megagrams (4,900,000 tons) raw value, an increase of over seven percent from 1978. Brazil, the leading shipper of raw sugar to the U.S., more than doubled its 1978 shipments. Twelve other countries shipped more than 91,000 megagrams (100,000 tons) total to the U.S. in 1979.

U.S. exports of raw sugar in 1979 were 2,541 megagrams (2,802 tons). The largest importer of U.S. sugar was Canada with approximately 2,157 megagrams (2,378 tons).[38]

Time series data. The financial analysis of the sugar cane industry is shown on Table 9-16. Profits were high during 1974 and 1975 as a result of the sugar shortage during those years. Profits then declined from 1976 until last year when sugar prices rose and production increased.

Profits reflect sugar mill locations within the U.S. From 1971 to 1977, Hawaii experienced an unprecedented period of drought that reduced production significantly. This was alleviated in 1978 and 1979. However, production in 1978 was negatively affected by some early harvesting due to such factors as smut disease and strikes. Since 1976, the net profit of the sugar cane industry has been low, with capital expenditures to total assets averaging 43 percent.

Information on financing investments is not complete due to the large number of closely held companies and diversified large companies. The

TABLE 9-15. HISTORIC TRENDS OF PRODUCTION FOR RAW CANE SUGAR MANUFACTURING INDUSTRY[a]

Indicator	1974	1975	1976	1977	1978	1979
Production[b] 10^3 Mg (10^3 st)	2806 (3094)	3209 (3538)	3037 (3348)	2921 (3220)	2739 (3020)	2780 (3065)
Production/mill 10^3 Mg (10^3 st)	37.42 (41.25)	44.57 (49.14)	42.77 (47.15)	42.95 (47.35)	57.41 (52.07)	51.48 (56.76)
Producer price index (1967 = 100)	217.80	283.40	286.00	281.80	283.20	309.40
Average price[c,d] ¢/kg (¢/lb.)	64.90 (29.50)	49.43 (22.47)	29.28 (13.31)	24.18 (10.99)	30.65 (13.93)	32.87 (14.94)
Total value of shipments[d,e] ($\$10^6$)	1262.10	1015.90	713.50	702.40	NA[f]	NA
Value of shipments/mill[d,e] ($\$10^6$)	16.83	14.11	10.05	10.33	NA	NA

[a]U.S. Department of Commerce. Bureau of Census. Agricultural Statistics 1979, Sugar and Sweetener Report. U.S. Department of Agriculture.

[b]Sugar production, raw value (equivalent of 96° sugar), approximately 10.34 percent of production for sugar.

[c]U.S. raw sugar price - New York basis.

[d]Dollar amounts in nominal terms.

[e]Includes syrup and molasses.

[f]NA denotes not available.

TABLE 9-16. FINANCIAL ANALYSIS -- RAW SUGAR CANE MANUFACTURING INDUSTRY[a]
(Nominal terms)

Financial indicator	1974	1975	1976	1977	1978	1979	Average (1974-1979)
Capital expenditures							
Total assets (10^6\$)	77.20	92.70	90.10	89.30	90.70	101.10	90.20
Capital expenditures/ firm (10^6\$)	30.80	36.80	40.70	39.40	40.90	46.70	39.20
Capital expenditures/ total assets (%)	39.85	39.67	45.14	44.18	45.09	46.22	43.48
Profitability							
Net profit after taxes (10^6\$)	20.26	24.76	10.14	7.16	4.75	9.78	12.81
Return on assets (%)	26.25	26.72	11.25	8.02	5.24	9.67	14.53
Return on equity (%)	21.95	22.73	9.29	6.33	6.14	10.85	12.88
Return on sales (%)	26.20	27.94	16.43	12.64	8.46	14.53	17.70
Dividends (\$/share)	2.41	2.19	1.93	1.40	1.47	1.59	1.83
Net earnings before interest and taxes (10^6\$)	62.47	46.29	17.17	12.30	7.39	14.82	26.74
Capitalization							
Interest on fixed obligations (10^6\$)	NA[b]	NA	NA	NA	1.63	2.75	2.19
Coverage ratio	NA	NA	NA	NA	4.54	5.38	5.00
Rating on bonds	NA	NA	NA	NA	NA	A/Baa	A/Baa
Long-term debt (10^6\$)	NA	NA	NA	NA	24.42	45.11	32.00
Stockholders' equity (10^6\$)	92.29	108.94	109.13	113.09	77.47	90.14	98.51
Debt/capitalization (%)	NA	NA	NA	18.96	23.97	33.35	24.52
Debt/equity (%)	NA	NA	NA	23.40	31.52	50.04	32.48

[a]Average/firm estimates for model firms (Securities and Exchange Commission; EEA estimates).

[b]NA denotes not available.

family held companies and farmers cooperatives finance predominantly from debt. The sugar corporations have been showing a similar trend over the last few years.

Sugar cane prices reached an all time high of $1.58/kilogram ($0.72/pound) on the spot market in 1974-1975. The value of shipments was also at a high of $1.3 billion during 1974. Since that time, the value of shipments has been gradually decreasing and production has been decreasing with the exception of 1975 and 1976.

Internationally, world sugar consumption has been on the rise since 1974. Prior to 1974, the U.S. sugar market was regulated by legislation designed to keep supply and demand in balance. In November 1979, the International Sugar Agreement was ratified to maintain world sugar prices within the $0.26 to $0.48/kilogram ($0.12 to $0.22/pound) range. However, due to the current reduction in world supply, prices will probably climb in 1980. Speculators are anticipating $0.99/kilogram ($0.45/pound) on the spot market. Sugar users believe these high prices will sap the sugar market share and lead to the substitution of other sweeteners.[39]

Five-year projections. Domestic sugar usage has been on the decline since the early 1970's. It is likely that per capita consumption will decline to around 187 kilograms (85 pounds) in the current decade, due to the increased use of high fructose corn syrup.

Several raw sugar companies have entered into the substitute market. The main concern of the raw sugar producers both now and in the future is increasing competition from imported raw sugar.[40] The compounded annual real growth rate for 1980-1985 is forecasted at 3.3 percent.[41]

9.1.1.4.3 Steam use. Approximately 90 to 100 percent of bagasse produced from the milling operation is burned as fuel. It is estimated that approximately 67.52 x 10^{12} KJ (64 x 10^{12} Btu) gross heat value was supplied by bagasse in 1979, producing 40.51 x 10^{12} KJ (38.4 x 10^{12} Btu) of heat.[42] Both Hawaiian and some Florida sugar mills generate electricity from bagasse. In 1978, the Hawaiian plantations generated a total of 669 million kWh and sold 187 million kWh to local electric utilities. In total, the Hawaiian plantations have roughly 180 megawatts of electrical generating capability. The Hawaiian sugar industry produced 2.87 million tons of bagasse in 1978 and burned 2.71 million tons as fuel.[43] The U.S.

Sugar Corporation, Florida's largest sugar cane producer, can generate 12 to 20 megawatts of electricity daily by burning up to 800 tons of bagasse.[44]

Most of the steam required is used for machine drive. The major manufacturing processes are described below.

- Milling. After the cane stalk enters the plant the juice is extracted with knives, shredders, crushers, and mills.

- Clarification and filtration. Remaining impurities in the juice are removed by a refining process. Clarification produces clarified juice (which is sent to the evaporators) and precipitated sludge (which is thickened by rotary vacuum filters).

- Evaporation. This is the most steam-intensive step in the milling process. Evaporators concentrate the juice to obtain a syrup which is about 60 percent solids.

- Crystallization. The sugar solution is super saturated to form crystals in vacuum pans which are then placed in centrifugals, washed, and discharged to storage.

- Packaging. The crystalline sugar is weighed, packaged, and moved to storage on belt or screw conveyors. From bulk storage in the warehouse, the sugar moves to refineries or is sent direct to market if "refining" is done in-house.[45]

9.1.2 Municipal Users

This section profiles four municipalities selected for analysis. These municipalities operate nonfossil fuel fired boilers or are planning to operate them in the near future. They are:

- Albany, New York
- Harrisburg, Pennsylvania
- Peekskill, New York
- Saugus, Massachusetts.

The selected municipalities represent four categories that could exhibit different economic impacts: category one, publicly owned NFFB's in economically distressed cities financed by State funds; category two, publicly-owned NFFB's in economically distressed cities financed by municipal funds; category three, publicly owned NFFB's in economically stable cities; and category four, privately run NFFB's. Albany, New York, falls into the first category; Harrisburg, Pennsylvania, fits into the second category; Peekskill, New York, into the third; and Saugus, Massachusetts, into the last category.

Table 9-17 lists the 44 municipalities that are currently operating NFFB's or are planning to operate them. This list was employed for selecting members in each user category.

To select the municipalities in categories one and two, the U.S. Department of Housing and Urban Development's (HUD) Urban Development Assistance Grant (UDAG) Eligibility List (December 1978), which lists economically distressed cities, was used. The list contains six indicators of economic well-being which are:

- The percent of population change between 1960 and 1975
- The unemployment rate in 1977
- The ratio of retail and manufacturing jobs in 1972 to jobs in 1967
- Nominal growth in per capita income between 1969 and 1974
- The poverty factor -- 1970 poverty level as a ratio of 1975 total population
- The ratio of housing built before 1939 to total housing in 1970.

The list specifies a median value of all municipalities. Only cities failing at least three of the six median values, that is, exceeding or falling short of the median, depending on the specific indicator, are included in the eligibility list. Municipalities that vary the most from the national median values for the greatest number of indicators can be considered the most economically distressed areas. Municipalities on the UDAG list that are firing or considering firing nonfossil fuels were ranked by the amount by which they failed each median. Albany and Harrisburg, which failed all six indicators, had the the highest rankings; they were chosen to represent marginal cities that operate NFFB's.

It is assumed that economically unstable municipalities may be more sensitive to changes in project costs than are other municipalities. Resource recovery projects are usually not high priority municipal expenditure items and, as such, higher costs of pollution control may lead to re-evaluation of a project more by municipalities that have unstable economic bases than by cities that have stable infrastructures. Furthermore, marginal cities typically have lower municipal bond ratings and consequently may have more difficulty acquiring incremental capital under alternative control levels.

The municipality in the third category was chosen because it is not on the UDAG list. As such, it is an economically stable city and may have impacts that differ from those users in the first and second categories. This municipality was also chosen because it is planning NFFB's for 1984 and therefore may be an actual facility affected by the alternative control level. The municipality in the last category is studied to analyze privately owned and operated facilities.

9.1.2.1 Albany, New York.

9.1.2.1.1 Municipality description. Albany, the capital of New York State, located in Federal Region 2, is comprised of approximately 110,300 people (1975 estimate). Between 1960 and 1975 Albany's population declined 15 percent from 129,700 to 110,300.[46]

As explained in Section 9.1.2, HUD's UDAG Eligibility List (December 1978) ranks municipalities by indicators of economic well-being such as the unemployment rate, change in retail and manufacturing employment, growth in per capital income, poverty level, and age of housing. Compared to the median national unemployment rate of 6.98 percent in 1977, Albany experienced 8.16 percent unemployment. The ratio of retail and manufacturing jobs in 1972 to 1967 was slightly lower in Albany than in the nation as a whole -- 0.94 in Albany as compared to 1.07 overall. Per capita income between 1969 and 1974 grew $1,276 (nominal dollars) in Albany while it increased $1,424 (nominal dollars) on average in all other municipalities. The poverty level in 1970 as a percent of total population in 1975, showed a similar trend. The median national factor was 11.24 percent; Albany's was 13.94 percent. Finally, 75 percent of housing in Albany was built before 1939 compared to 34 percent for all other municipalities. The age of housing can affect the municipal tax base as older units are normally assessed lower than newer units.

9.1.2.1.2 NFFB facility description. Albany's resource recovery system, which is expected to come fully on-line by the end of 1981, is a cooperative effort between New York State and Albany. The two parties have separate responsibilities: the city will collect the garbage, convert it into RDF, a more usable form of raw garbage, and transport it to the State's boiler plant; the State will then burn the RDF in two new boilers and produce steam for space conditioning in State office buildings. The city will then take care of the disposal of post-combustion ash.

TABLE 9-17. MUNICIPAL USERS OF NONFOSSIL FUEL FIRED BOILERS[a]

Location	Process	Output	Nonfossil fuel capacity (tons per day)	Status (on-line)
Akron, OH	Burns RDF	Steam for urban and industrial heating and cooling	1,000	1980
Albany, NY State Energy Office	To burn RDF	Steam for heating and cooling State office buildings	750	1981
Auburn, ME	Mass combustion of MSW in small modular combustion units	Steam	200	11/1980
Baltimore, MD	Pyrolysis	Steam for use by city utility	600	Operational
Batesville, AR	Mass combustion of MSW	Steam	50	1981
Blytheville, AR	Mass burning of of MSW	Steam	75	Unknown

TABLE 9-17 (Continued). MUNICIPAL USERS OF NONFOSSIL FUEL FIRED BOILERS[a]

Location	Process	Output	Nonfossil fuel capacity (tons per day)	Status (on-line)
Braintree, MA	Mass burning	Steam, sells half to industry	250	1971
Burley, ID	Mass combustion	Steam	50	1980
Chicago, IL (Northwest Incinerator)	Waterwall incineration	Steam for industrial use	1,600	1971
Columbus, OH	To burn shredded refuse with coal in boiler	Electricity for city customers	2,000	1982
Crossville, TN	Mass combustion of MSW	Steam	60	Unknown
Dade County, FL	Unknown	Steam for electric utility	3,000	1981
Detroit, MI	Burning in dedicated boilers	Steam and/or electricity for Detroit Edison	3,000	Unknown

TABLE 9-17 (Continued). MUNICIPAL USERS OF NONFOSSIL FUEL FIRED BOILERS[a]

Location	Process	Output	Nonfossil fuel capacity (tons per day)	Status (on-line)
Duluth, MN	Fluidized bed incineration of RDF and sludge	RDF; steam for heating and cooling plant and to run equipment	400 MSW; 340 sludge	1980
Durham, NH	Mass combustion of MSW	Steam	108	1980
Dyersburg, TN	Mass combustion of MSW	Steam	100	1980
Gallatin, TN	Mass burning in waterwall combustion	Steam for industrial use and electricity generation	200	1981
Gatesville, TX	Mass combustion	Steam	7	1981
Genessee Township, MI	Mass combustion of MSW	Steam	100	1980

TABLE 9-17 (Continued). MUNICIPAL USERS OF NONFOSSIL FUEL FIRED BOILERS[a]

Location	Process	Output	Nonfossil fuel capacity (tons per day)	Status (on-line)
Glen Cove, NY	Mass burning	Steam for electricity for use at sewage plant	225	Unknown
Groveton, NH	Mass combustion of MSW	Steam	24	1975
Hampton, VA	Waterwall incineration	Steam for use by NASA Langley Research Center	200	1980
Harrisburg, PA	Waterwall combustion	Steam for utility-owned district heating system and city-owned sludge drying system	750	1972
Lakeland, FL	To burn RDF with coal	Steam to produce electricity for use by city of Lakeland and Orlando Utility Commission	300	1981

TABLE 9-17 (Continued). MUNICIPAL USERS OF NONFOSSIL FUEL FIRED BOILERS[a]

Location	Process	Output	Nonfossil fuel capacity (tons per day)	Status (on-line)
Lewisburg, TN	Mass combustion of MSW	Steam	60	1981
Nashville, TN	Thermal combustion	Steam for urban heating and cooling	400	1974
Newport News, VA	Mass combustion of MSW	Steam	40	1981
Niagara Falls, NY	Burns shredded refuse	Steam/electricity for industrial use	2,200	1980
Norfolk, VA (U.S. Naval Station)	Mass burning in waterwall furnace	Steam for use by Naval Station	360	Operational
North Little Rock, AR	Mass combustion of MSW	Steam	100	Operational
Oceanside, NY	Mass burning in waterwall furnace	Steam for electricity generation	750	1965

TABLE 9-17 (Continued). MUNICIPAL USERS OF NONFOSSIL FUEL FIRED BOILERS[a]

Location	Process	Output	Nonfossil fuel capacity (tons per day)	Status (on-line)
Orange County, FL (Walt Disney World)	Pyrolysis incineration	High temperature water for heating and cooling	100	Unknown
Osceola, AR	Mass combustion of MSW	Steam	50	1980
Palestine, TX	Mass combustion of MSW	Steam	28	1981
Peekskill, NY	Mass burning in waterwall furnaces	Steam and electricity for sale to utility	1,500	1984
Pinellas County, FL	Mass burning	Electricity to be sold to Florida Power & Light	2,000	1983
Pittsfield, MA	Mass combustion of MSW	Steam	240	9/1980

TABLE 9-17 (Continued). MUNICIPAL USERS OF NONFOSSIL FUEL FIRED BOILERS[a]

Location	Process	Output	Nonfossil fuel capacity (tons per day)	Status (on-line)
Portsmouth, VA (Norfolk Naval Shipyard)	Mass burning in waterwall furnace	Steam for use use by facilities at Naval Shipyards	160	1976
Portsmouth, VA (Southeastern Tidewater Energy Project)	To burn RDF	RDF, steam and electricity for shipyard	2,000	1981
Salem, VA	Mass combustion of MSW	Steam	100	1979
Saugus, MA	Waterwall combustion	Steam for electricity generation and industrial use	1,200	1975
Siloam Springs, AR	Mass combustion	Steam	16	1975

TABLE 9-17 (Continued). MUNICIPAL USERS OF NONFOSSIL FUEL FIRED BOILERS[a]

Location	Process	Output	Nonfossil fuel capacity (tons per day)	Status (on-line)
Waukesha, WI	Mass burning in refractory furnace	Steam for local industry and sewage treatment plant	120	1981
Windham, CN	Mass combustion of MSW	Steam	108	1981

[a]National Center for Resource Recovery. Resource Recovery Bulletin (10:3). September 1980.

The RDF NFFB system will be mutually beneficial to both the city and the State. The city, foreseeing insufficient landfill space in the near future, needed a reliable long-term means with which to dispose of municipal garbage. New York State, presently using oil-generated steam to heat and cool State office buildings, foresaw the burning of RDF as a major savings in fuel oil expenses.

The State and the city will share the costs of the project: the State will own and operate the two new refuse burning boilers, while the city will fund the refuse shredding equipment and the ash removal equipment. Total capital costs of the project are reported at $26.6 million -- $15 million for the steam plant and $11.6 for the RDF processing plant.[47]

Tables 9-18 and 9-19 present brief fiscal profiles of Albany and New York State, respectively. While Albany's profile is included only as background material, New York's is depicted because it is financing the two new boilers. Several expenditure indicators from the State profile will be related to incremental costs from alternative control levels presented in Section 9.2.

New York State is building the new RDF-fired plant adjacent to its six existing oil-fired boilers that have a total heat input capacity of approximately 176 MW (600 MMBtu/hr). The two new NFFB's will add another 94 MW (320 MMBtu/hr) approximately for a total plant capacity of 270 MW (920 MMBtu/hr). The NFFB's will operate continuously (24 hours/day, 365 days/year) and will satisfy baseload steam needs. The existing, more expensive oil-fired plant will then primarily satisfy peakload steam requirements. By relying less on its oil-fired plant, and more on the new RDF boilers, the State anticipates savings of $2 million to $2.5 million by reducing fuel oil consumption by about 6.1 million gallons a year.[48]

Table 9-20 depicts the boiler facility that is under construction in Albany. By 1981 it is projected that two RDF boilers, each rated at approximately 42.9 MW (144.8 MMBtu/hr) heat input, will be operational. Each boiler will be designed to consume a maximum of 272 megagrams (300 tons) of refuse derived fuel per day. Particulate matter emissions will be curtailed through use of an electrostatic precipitator on each boiler.

The following are some salient points regarding resource recovery at the Albany NFFB facility:

- RDF will be collected from the municipal waste processing center and stored in pits at the steam generating plant. A supply of oil is kept on hand in case there are inadequate refuse quantities or if refuse for some reason becomes uneconomical.

- RDF will be fired in two boilers that are each capable of handling 272 megagrams (300 tons) of RDF per day.

- Each NFFB will have an electrostatic precipitator to control emissions of particulate matter.

- Post-combustion ash will be collected and used as a substitute for gravel.

9.1.2.2 Harrisburg, Pennsylvania.

9.1.2.2.1 Municipality description. Harrisburg, the capital of Pennsylvania, located in Federal Region 3, comprises approximately 58,300 people (1975 estimate). The major industries in the area include steel works and rolling mills, blast furnaces, railroad repair shops, printing and publishing, slaughtering and meat packing.[49]

In recent years the city of Harrisburg has faced various social and economic problems, including declining population, mediocre bond rating, unemployment at a rate higher than the national average, declining manufacturing base, small growth in per capita income, and a high poverty level. Between 1960 and 1975, the population of Harrisburg declined 27 percent from 79,700 to 58,300. In Moody's Municipal and Government Manual 1980, Harrisburg received an average credit rating of Baa (on a scale of Aaa to C) on its general debt obligations.

Harrisburg performed below the national average in all UDAG indicators of municipal economic well-being. Harrisburg's unemployment rate was 7.6 percent in 1977 while the median national rate was approximately 6.98 percent. Retail and manufacturing jobs in 1972 as a percentage of 1967 was much lower in Harrisburg than in the entire nation; the nation's median ratio was 1.07, while Harrisburg's fraction was only 0.84. Per capita income growth between 1969 and 1974 showed a similar trend. The national median change during that period was $1,424 (nominal dollars), yet the change in Harrisburg was only $1,180 (nominal dollars). Relating the poverty level in 1970 to total population in 1975, Harrisburg experienced 23.83 percent poverty compared to the national median of 11.24 percent. Finally, 74 percent of Harrisburg's buildings were constructed prior to 1939, compared to 34 percent nationally.

TABLE 9-18. FISCAL PROFILE OF ALBANY, NEW YORK[a]

Item	1962 Amount	1962 %	1967 Amount	1967 %	1972 Amount	1972 %	1977 Amount	1977 %
Population	129,726[b]	---	129,726[b]	---	115,781[c]	---	110,311[d]	---
General revenue:[e]	18,676	100.0	25,222	100.0	44,621	100.0	43,554	100.0
From federal/state	4,157	22.3	8,340	33.1	20,669	46.3	18,539	42.6
From city	14,519	77.7	16,882	66.9	23,952	53.7	25,015	57.4
Utility revenue[e]	1,845	---	1,792	---	2,288	---	797	---
General expenditures:[e]	17,942	100.0	33,655	100.0	51,358	100.0	48,460	100.0
Education[f]	8,093	45.1	10,852	32.3	20,350	39.6	835	1.7
Transportation	1,375	7.7	1,999	5.9	3,758	7.3	3,482	7.2
Health & safety[g]	2,930	16.3	3,546	10.5	6,646	12.9	11,744	24.2
Sewerage & sanitation	754	4.2	954	2.8	5,958	11.6	7,622	15.7
Interest on debt	797	4.4	1,204	3.6	3,212	6.3	3,329	6.9
All other	4,001	22.3	15,111	44.9	11,453	22.3	21,468	44.3
Utility expenditure[e]	1,445	---	1,910	---	2,351	---	3,975	---
Long-term debt[e]	29,250	---	33,298	---	20,166	---	55,099	---

[a]Department of Commerce. Bureau of the Census. 1967, 1972, 1977 Census of Governments.

[b]1960 Census.

[c]1970 Census.

[d]1975 estimate.

[e]10^3 dollars.

[f]Includes education and libraries.

[g]Includes health, hospital, police, and fire protection.

TABLE 9-19. FISCAL PROFILE OF NEW YORK STATE[a]

Item	1974 Amount	1974 %	1978 Amount	1978 %
Population	18,111,000		17,748,000	
Revenue[b]	8,635.3	100.0	11,148.2	100.0
Taxes:	8,102.1	93.8	10,475.4	94.0
Income tax	3,352.0	38.8	4,476.2	40.2
Business	1,296.1	15.0	1,998.8	17.9
Sales	1,863.2	21.6	2,412.3	21.6
Other taxes	1,590.8	18.4	1,588.1	14.2
Other	533.2	6.2	672.8	6.0
Total expenditures[b]	8,508.0	100.0	11,146.8	100.0
Local assistance:	5,110.8	60.0	6,633.5	59.5
Education	2,817.9	33.1	3,512.1	31.5
Social welfare	1,250.0	14.7	1,716.5	15.4
General assistance	548.6	6.4	718.6	6.4
Health	226.8	2.7	242.2	2.2
Housing	68.4	0.8	61.6	0.6
Other	195.7	2.3	379.0	3.4
State purposes:[b]	2,741.7	32.2	3,651.8	32.8
Education	707.1	8.3	855.6	7.7
Health	599.7	7.0	758.5	6.8
Executive	267.1	3.1	326.9	2.9
Transportation	207.2	2.4	239.9	2.2
Other	969.9	11.4	1,471.4	13.2
Capital construction[b]	360.2	4.2	445.2	4.0
Debt service[b]	295.3	3.5	416.2	3.7

[a]Moody's Municipal and Government Manual 1980; The Statistical Abstract, 1975; The Statistical Abstract, 1979.

[b]10^3 dollars.

TABLE 9-20. BOILER CONFIGURATION OF THE ALBANY, NEW YORK, NFFB FACILITY

Boiler plant		
Total firing rate in MW (MMBtu/hr) heat input:	71.6 (244)	
Total number of boilers:	2	
Characteristics of individual boilers		
Boiler #	1	2
Heat input capacity MW (MMBtu/hr)	42.9 (144.8)[a]	42.9 (144.8)[a]
Megagrams of RDF/day capacity (tons/day)	272 (300)	272 (300)
Fuel design type	RDF	RDF
Process employed	Direct firing of RDF	Direct firing of RDF

[a]Conversion from tons/day to MMBtu/hour assumes 5790 Btu/lb of RDF.

Table 9-21 presents the fiscal characteristics of the city over the years 1962, 1967, 1972, and 1977. As the table shows, shifts have occurred in the shares of the items that comprise general revenue. In 1977, a greater share of revenues came from State and Federal revenues and less from the city of Harrisburg itself than in any of the three previous years shown. This has meant a greater reliance on outside sources to carry the city through its expenditure needs. Shares of general expenditures have fluctuated through the years. By 1977, health and safety (hospitals, police, and fire protection), sewerage and sanitation, and transportation expenses comprised the largest expenses.

9.1.2.2.2 NFFB facility description. The city of Harrisburg has been operating two solid waste heat recovery (waterwall combustion) units since 1972. Municipal, commercial, and industrial wastes are collected from nearby areas and converted to steam energy. Each steam unit is capable of processing 379 megagrams (360 tons) of refuse daily or, assuming 4,875 Btu's per pound of refuse, 3,703.1 million GJ (3,510 million Btu's). The facility had functioned previously as a municipal incinerator but was retrofitted in the early 1970's to produce steam energy. The boilers serve two needs: they dispose of accumulated wastes and they produce steam to heat and cool city buildings, a savings in fuel expenses.

Table 9-22 outlines the configuration of the Harrisburg NFFB facility. The plant consists of two boilers, each of which has a design heat input rating of 42.8 MW (146 MMBtu/hr). Correspondingly, each boiler is capable of consuming 327 megagrams (360 tons) of refuse per day. The plant is functioning continuously. Each furnace is equipped with an electrostatic precipitator (ESP) to control emissions of particulate matter.

The steam generated at the NFFB plant has a variety of uses. One share of the steam produced is channeled through a downtown Harrisburg heating system of Pennsylvania Power & Light Company. A two-mile steam pipe was completed in 1978 and steam sales to that system began by the end of the year.[50] Steam serves in-house needs also -- to power the refuse shredder turbine, heat the steam plant in the winter, and serve some nearby municipal buildings.

In the near future, steam will be used in a sludge drying process at the plant. The NFFB's are being modified to accept dried sewage sludge

TABLE 9-21. FISCAL PROFILE OF HARRISBURG, PENNSYLVANIA[a]

Item	1962 Amount	1962 %	1967 Amount	1967 %	1972 Amount	1972 %	1977 Amount	1977 %
Population	79,697[b]	---	79,697[b]	---	68,061[c]	---	58,274[d]	---
General revenue:[e]	6,850	100.0	7,484	100.0	11,419	100.0	17,258	100.0
From federal/state	1,824	26.6	927	12.4	3,110	27.2	5,554	32.2
From city	5,026	73.4	6,557	87.6	8,309	72.8	11,704	67.8
Utility revenue[e]	881	---	912	---	1,064	---	1,857	---
General expenditures:[e]	5,999	100.0	6,912	100.0	13,140	100.0	15,352	100.0
Education[f]	5	---	10	---	----	---	20	---
Transportation	932	15.5	1,400	20.3	1,304	9.9	1,647	10.7
Health & safety[g]	1,436	23.9	1,871	27.1	3,100	23.6	4,578	29.8
Sewerage & sanitation	1,133	18.9	1,285	18.6	1,851	14.1	2,720	17.7
Interest on debt	123	2.1	118	1.7	166	1.3	542	3.5
All other	2,376	39.6	2,233	32.3	6,715	51.1	5,880	38.3
Utility expenditure[e]	568	---	775	---	479	---	752	---
Long-term debt[e]	2,505	---	3,675	---	4,286	---	8,157	---

[a]Department of Commerce. Bureau of the Census. 1962, 1967, 1972, 1977 Census of Governments.

[b]1960 Census.

[c]1970 Census.

[d]1975 estimate.

[e]10^3 dollars.

[f]Includes education and libraries.

[g]Includes health, hospital, police and fire protection.

TABLE 9-22. EXISTING BOILER CONFIGURATION OF THE HARRISBURG, PENNSYLVANIA, NFFB FACILITY

Boiler plant		
Total firing rate in MW (MMBtu/hr) heat input:	85.6 (292)	
Total number of boilers:	2	
Characteristics of individual boilers		
Boiler #	1	2
Heat input capacity MW (MMBtu/hr)[a]	42.8 (146)	42.8 (146)
Megagrams of refuse/day capacity (tons/day)	327 (360)	327 (360)
Fuel design type	Refuse	Refuse
Process employed	Incineration	Incineration

[a]Assumes 4875 Btu/lb of refuse.

along with municipal solid waste. Wet sludge must first be pumped in from a wastewater treatment plant and then dewatered in filters and dried in steam-heated dryers.

The plant cost approximately $8.3 million to build and convert. Project financing came primarily from a municipal bond issue and a Federal grant. This cost estimate does not include land and the more recent steam pipeline and sludge drying systems.

The following briefly outlines important points about the resource recovery at the Harrisburg plant:

- Private refuse haulers deliver truckloads of municipal garbage to the processing site. A tipping fee of $8 to $12/megagram ($9 to $13/ton) is charged.
- Refuse is delivered to the site at a daily rate of approximately 454 megagrams (500 tons).
- Usually one boiler is in operation at a time; however, when accumulations of refuse are high, both boilers may operate simultaneously.
- Only bulky items are shredded before combustion in the furnaces.
- The furnaces have electrostatic precipitators to control particulate matter emissions.

9.1.2.3 Peekskill, New York.

9.1.2.3.1 Municipality description. Peekskill, New York, situated in Federal Region 2, comprises 20,552 people (1975 estimate). Table 9-23 shows a brief fiscal profile of Peekskill. In each year studied, successively greater shares of revenues have come from Federal and State sources and less from the city of Peekskill itself. In 1962, approximately 87 percent of revenue sources come from the city and 13 percent from New York State and Federal funds; however, in 1977, the shares of total revenues were almost equally split between city sources and State and Federal sources. At the same time, the size of the overall budget almost quadrupled during the 16-year period studied. On the municipal expenditure side, health and safety, transportation, and sewerage and sanitation took the largest shares of city funds in the four years presented.

Peekskill was selected for analysis because it is not economically distressed as were several of the other municipalities chosen. As a more economically stable city, it should be able to afford an NFFB even under a more stringent control level. Furthermore, economic factors may be less important than is the need to alleviate a potential waste disposal problem. Therefore, Peekskill represents a different NSPS impact candidate.

9.1.2.3.2 NFFB facility description. The city of Peekskill and the county of Westchester are the two main participants in planning the NFFB facility. The city will house the steam producing plant. The county presently manages Westchester's waste disposal. As the plant is expected to begin producing steam in 1984, specific details on its eventual operation are unknown.

It is reported that the facility could consume annually between 453,500 and 498,850 megagrams (500,000 and 550,000 tons) of garbage to generate steam primarily for electricity. Table 9-24 depicts salient characteristics of the New York plant at completion according to present plans. The plant is expected to contain two MSW boilers each capable of firing 85.7 MW (292 MMBtu) heat input.

The new plant is expected to burn eventually more than half the garbage now generated in Westchester County. Thirty-four nearby communities are planning to supply garbage to the plant.[51] The energy that is to be produced will fulfill the electricity needs of Peekskill and several nearby cities and may be sold at a later date to electric utilities such as Consolidated Edison and the Power Authority of the State of New York.

It is estimated that the new plant will cost approximately $80 million.[52] Project financing may come from several sources -- project revenue bonds issued by the County's Industrial Development Agency and $27 million in New York State Environmental Quality Bond Act funds. A $17/ton tipping fee charged in the first five years of operation is expected to offset some of the project costs.[53]

9.1.2.4 Saugus, Massachusetts.

9.1.2.4.1 Municipality description. Saugus, Massachusetts, ten miles north of Boston, is located in Federal Region 1. It is a small residential suburb of approximately 24,600 people (1975 estimate) whose population increased over 19 percent between 1960 and 1975.[54]

9.1.2.4.2 NFFB facility description. The Saugus, Massachusetts resource recovery facility has been collecting municipal refuse and generating steam continuously since 1975. Presently, waste products are re-

TABLE 9-23. FISCAL PROFILE OF PEEKSKILL, NEW YORK[a]

Item	1962 Amount	1962 %	1967 Amount	1967 %	1972 Amount	1972 %	1977 Amount	1977 %
Population	18,337[b]	---	18,337[b]	---	19,283[c]	---	20,552[d]	---
General revenue:[e]	1,537	100.0	1,839	100.0	3,516	100.0	7,154	100.0
From federal/state	206	13.4	381	20.7	1,137	32.3	3,466	48.4
From city	1,331	86.6	1,457	79.2	2,379	67.7	3,688	51.6
Utility revenue[e]	373	---	393	---	475	---	849	10.6
General expenditures:[e]	1,530	100.0	2,353	100.0	3,578	100.0	7,310	100.0
Education[f]	28	1.8	37	1.6	56	1.6	110	1.5
Transportation	296	19.3	271	11.5	290	8.1	1,312	17.9
Health & safety[g]	399	26.1	532	22.6	917	25.6	1,595	21.8
Sewerage & sanitation	320	20.9	688	29.2	357	10.0	411	5.6
Interest on debt	73	4.8	53	2.3	185	5.2	344	4.7
All other	415	27.1	772	32.8	1,771	49.5	3,545	48.5
Utility expenditure[e]	352	---	366	---	704	---	733	---
Long-term debt[e]	4,905	---	857	---	2,390	---	4,420	---

[a] Department of Commerce. Bureau of the Census. 1962, 1967, 1972, 1977 Census of Governments.

[b] 1960 Census.

[c] 1970 Census.

[d] 1975 estimate.

[e] 10^3 dollars.

[f] Includes education and libraries.

[g] Includes health, hospital, police, and fire protection.

TABLE 9-24. BOILER CONFIGURATION OF THE PEEKSKILL, NEW YORK, NFFB FACILITY

Boiler plant		
Total firing rate in MW (MMBtu/hr)	171.4 (584)	
Total number of boilers:	2	
Characteristics of individual boilers		
Boiler #	1	2
Heat input capacity[a] MW (MMBtu/hr)	85.7 (292)	85.7 (292)
Megagrams of refuse/day capacity (tons/day)	652.3 (719)	652.3 (719)
Fuel design type	MSW	MSW
Process employed	Mass combustion	Mass combustion

[a]Assumes 4875 Btu/lb of refuse.

ceived from nearby communities and burned in boilers to provide steam solely for local industrial use.

Although it burns municipal wastes, the plant is not owned and operated by the city of Saugus. Rather, the Refuse Energy Systems Co. (RESCO), a private company formed by the joint venture of Wheelabrator-Frye, Inc. and M. DeMatteo Construction Company, owns and operates the Saugus plant. DeMatteo Construction Co. had been the owner of a major landfill servicing many communities in the area that was closed for environmental reasons. The company still wanted to provide the waste disposal service and therefore pursued the RESCO project along with Wheelabrator Frye.

The Saugus facility cost approximately $40 million (1975 dollars), $30 million of which came from solid waste disposal revenue bonds and $10 million resulting from equity of the two parties.

Two factors ensure a constant revenue base for the plant. First, long-term contractual arrangements with local municipalities guarantee an adequate supply of refuse and tipping fees. Second, a contractual industrial purchaser of steam ensures a regular flow of revenues.

Refuse is received from 18 nearby communities that currently pay $17.1/megagram ($15.5/ton) to dispose of their municipal refuse. In the near future the number of these contractual arrangements is expected to rise as the tipping fees charged to the municipalities become more competitive with the costs of alternative waste disposal.

A General Electric (GE) plant located directly across from the Saugus facility purchases 100 percent of the steam generated via a steam pipe. Coincidentally, when RESCO was considering building the resource recovery plant several years ago, GE needed to replace two boilers to satisfy its steam needs. Instead of purchasing new boilers, GE agreed to buy its steam requirements from the resource recovery facility. GE saved the costs of new boilers and RESCO gained a steam customer.

Table 9-25 shows the basic configurations of the refuse-fired boilers in Saugus. Two MSW-fired boilers each rated at 89.4 MW (305 MMBtu/hr) heat input are operating. Each boiler is capable of processing daily 680 megagrams (750 tons) of refuse.

The Saugus facility employs the waterwall combustion technology for converting municipal wastes to steam energy. The following briefly outlines the flow of refuse to energy at the plant:

- Refuse collection trucks haul municipal waste to the plant's receiving pit, a container capable of holding 6,349 megagrams (7,000 tons) of garbage or approximately a five-day supply of refuse for the two boilers.

- Normally refuse as-received is charged into the boilers. Only overly large items are shredded.

- An electrostatic precipitator controls air emissions.

- 100 percent of the steam generated is conveyed to the nearby GE plant.

- Two standby oil-fired boilers of the same general capacity are maintained to guarantee a reliable supply of steam.

9.2 ECONOMIC IMPACT ANALYSIS

9.2.1 Introduction

This section discusses the economic impacts on industrial and municipal users of nonfossil fuel fired boilers (NFFB) resulting from a New Source Performance Standard (NSPS) and the methodology used to determine those impacts. Presently, NFFB's are subject to emission regulations required by the State Implementation Plans (SIPs). These emission regulations constitute the base case level of pollution control and serve as a baseline for comparison to alternative pollution control levels. This analysis assumes that in the base case all NFFB's are covered under the applicable SIP. The ensuing analysis seeks to identify the incremental pollution control costs and the economic impacts that could result from requiring controls that are more stringent than those employed in response to State regulations.

9.2.2 Impact on Selected Industrial Users

This section outlines the methodology used to assess economic impact, discusses the potential impacts on the five manufacturing industries, and presents the model plant parameters and selected control level results for each of the five industries.

9.2.2.1 Methodology of Economic Impact Analysis. The economic impact analysis of selected industries focuses on the effect Control Levels I and II have on product cost and price, profitability, and capital availability.

9.2.2.1.1 Product cost impacts. To estimate the impact of alternative control levels on production costs, three determinations are made: a model plant for the selected industry is defined, cost impacts for the

TABLE 9-25. EXISTING BOILER CONFIGURATION OF THE SAUGUS, MASSACHUSETTS, PLANT

Boiler plant		
Total firing rate in MW (MMBtu/hr) heat input:	178.8 (610)	
Total number of boilers:	2	
Characteristics of individual boilers		
Boiler #	1	2
Heat input capacity[a] MW (MMBtu/hr)	89.4 (305)	89.4 (305)
Megagrams of refuse/day capacity (tons/day)	680 (750)	680 (750)
Fuel design type	MSW	MSW
Process employed	Mass burning	Mass burning

[a]Conversion from tons/day to MMBtu/hr assumes 4875 Btu/lb of refuse.

model plant are determined, and the ability of the firm to either absorb the incremental costs incurred by the alternative control levels or pass on the additional costs is discussed.

The selected industries analysis uses model plants to measure the economic impact of alternative control levels on each industry. A model plant is used because it is difficult to obtain precise details about the expansion and replacement plans of actual industries. The model firm and plant/mill configurations were based on the following indicators:

- The firm represents that portion of the industry most likely to invest in a new boiler due to its market share.
- The plant/mill represents what is "typical" for that portion of the industry.
- The boiler expansion or replacement decision is based on both the economics of the industry and its projected growth rate for the next five years.

For this analysis, each plant within the industry is assumed to be identical with regard to steam use relative to product output. The fuel type burned in the existing boiler(s) of the model plant is determined by industry survey.

The following production characteristics of the model plant are supplied:

- Plant output/year. Average product output per year in those plants most likely to invest in new boilers.
- Producer price/unit of output. The historic average selling price per unit, in 1978 dollars.
- Plant sales/year. Plant output per year multiplied by price per unit of output.
- Plant earnings/year. Plant sales per year multiplied by a derived profit margin. This figure estimates the profitability of the model plant.

The effect of alternative emission control levels on product cost is calculated from the new cost of steam, the share of steam affected by the regulation, and the amount of steam consumed per dollar of output. The cost impacts are stated in real 1978 terms. All other production costs are held constant.

In this analysis, wholesale prices are used as a proxy for production cost. Retail prices are not used since they are subject to variables, such as price markups, that would not occur as a direct result of the alternative control levels.

The ability of an industry to pass on the additional costs of alternative emission regulations is evaluated. The competitive market position of an industry's product determines the extent to which an industry can pass on additional costs.

9.2.2.1.2 Profitability impacts. The financial well-being of the industry determines its ability to absorb additional costs. The second consideration, therefore, is profitability impacts; that is, how incremental costs of emission control affect two profitability indicators -- return on sales and return on total assets. To determine this impact, a new net profit figure is calculated. The percent change in producer price due to the control level is multiplied by base case income statement expenses to yield a total dollar change. This dollar change is then added to base case expenses and a net profit under the alternative control level is calculated. Sales are assumed to be constant for all selected control levels and expenses increase only as a result of the new boiler investments. A new return on sales and return on assets due to the regulation can then be calculated and compared to the same ratios in the base case.

9.2.2.1.3 Capital availability. Capital availability constraints may result if alternative emission regulations create a need for financing additional pollution control investments. The following steps are used to evaluate whether capital availability will be a constraint for a selected industry: one, define financial indicators for the model firm; and two, evaluate the ability of a firm to finance pollution control investments.

The firm is the focus of the financial analysis because decisions involving large capital expenditures are made at the corporate level. Depending upon the state of corporate cash reserves and the relative costs of various financing tools, a firm will choose a combination of internal and external financing instruments to meet the additional investments required to comply with alternative regulations.

The capital availability analysis focuses on the following two financial indicators that measure each industry's financing ability:

- Cash flow coverage ratio. The number of times operating income (earnings before taxes and interest expenses) covers fixed obligations (annual interest on debt instruments and long-term leases).

- Book debt/equity ratio. A measure of the relative proportions of two types of external financing.

These two indicators are analyzed under the base case and under the alternative control cases. The change in indicators due to alternative control levels is analyzed to determine how difficult it might be for the firm to meet financial requirements for the pollution control equipment investment.

The cash flow coverage ratio is calculated by dividing operating income by fixed obligations. Both the operating income and fixed obligations could change as a result of alternative control levels. If the coverage ratio remains above 3.0, a standard benchmark, the cost of capital can be assumed to be above "acceptable" levels. Note, however, that as the coverage ratio falls, the cost of obtaining capital will rise.

The debt/equity ratio is calculated by dividing total long-term debt by total equity of the firm (book values). The incremental debt incurred from financing the pollution control required by alternatives is added to the base case debt; the incremental equity issued to finance the remainder of the investment is added to the base case equity. A new debt/equity ratio then is calculated. The change in the debt/equity ratio is analyzed to see how the alternatives will affect the firm's capital structure.

To determine the coverage and debt/equity ratios under the alternatives, five financing strategies are considered, which differ by the percentages of the investment financed by new debt versus new equity. (Note that for the changes in coverage ratios and debt/equity ratios, 100 percent external financing is assumed.) These external financing scenarios are: 1) zero percent new debt, 100 percent new equity; 2) 25 percent new debt, 75 percent new equity; 3) 50 percent new debt, 50 percent new equity; 4) 75 percent new debt, 25 percent new equity; and 5) 100 percent new debt, zero percent new equity.

The financial indicators generated for this analysis were derived from a variety of published sources. Robert Morris Associates' Annual Statement Studies was consulted for composite industry financial data. More specific corporate figures were collected from Moody's Industrial Manuals, Form 10-K's, and Annual Reports on file at the Securities and Exchange Commission.

9.2.2.2 Summary of Results. The results of the economic analysis indicate that the alternative control levels examined do not significantly affect the selected industrial users. Any impact resulting from the alternative control levels is summarized in Table 9-26 and explained in more detail in the following sections, which describe the model plant/mill and selected control level results for each industry. As seen in Table 9-26, all industries experience a product price increase of less than one percent. This is significantly lower than the five percent benchmark established by EPA. In the change in profit margin analysis, no industry experiences a significant decline in net income due to increased expenditures from the boiler investment. The return on assets percentage decline is also insignificant under the Level II alternative. The capital availability analysis, which assumes that the most stringent control level is required at 100 percent new debt financing, indicates that all industries can obtain additional capital.

9.2.2.3 Furniture Manufacturing Industry.

9.2.2.3.1 Model plant description. The major characteristics of the model firm are listed in Table 9-27. Financial characteristics are based on 1978 data taken from Table 9-3 in Section 9.1.

This model plant is located in the southern United States (Federal Region 4) where the furniture industry concentration is greatest. The plant is run continuously.

Total annual plant sales of furniture average $5 million. Production figures are not commonly used as a basis for comparison in the furniture industry since there are so many different categories of furniture (such as bedroom and dining room) and varying types within those categories (such as tables and chairs). Net profits for the model firm are assumed to be 3.3 percent of total sales or about $167,000. With industry sales estimated at $9.3 billion, this firm represents approximately 0.05 percent of the furniture market.

The model plant boiler house consists of three wood-fired boilers with a total heat input capacity of 26.4 MW (90 MMBtu/hr). Model boiler #1, found in Section 6, is closest in size to the furniture industry's existing two wood-fired boilers of 4.7 MW (16 MMBtu/hr) at 100 and 50 percent capacity utilization. Table 9-27 describes the individual boilers. The first boiler is operated at capacity the entire year. The second boiler is operated as a supplemental boiler during the winter months. Coal and fuel oil are used as a supplemental fuel during three months in the winter. Since these fossil fuels only contribute approximately 6 percent during the entire year, the two boilers are still classified as wood-fired. During the summer months, all of the steam is generated for process use. During the winter, only 40 percent of total steam is generated for process use and the remaining 60 percent is generated for space heat. The boiler investment decision is to replace the standby boiler. This new wood-fired boiler would generate one-third of total steam at the plant. The furniture industry is interested in generating its electricity through cogeneration; however, this would require a change in the present electric rate structure.

9.2.2.3.2 Selected control level results. The model plant replacement boiler is assumed to be a wood-fired boiler requiring PM control at all selected control levels. The price impacts of the selected control levels for the furniture industry cannot be assessed due to the absence of price and production figures. Lacking this information, the change in product price and the change in profit margin is not calculated.

Table 9-28 shows the pre-tax 1978 boiler and pollution control costs for the two selected control levels for the furniture industry. The two selected control levels, explained in Chapter 6, are represented by model boiler #1b, which requires 97 percent PM reduction [64.5 ng/J (0.15 lb/MMBtu) ceiling] and model boiler #1e, which requires 99 percent PM reduction [21.5 ng/J (0.05 lb/MMBtu) ceiling]. Boiler and pollution control costs for the boiler investment range from about $1.9 million in the base case to $2.3 million in the 99 percent PM reduction level.

As seen in Table 9-29, the steam requirement per unit of output is estimated at 0.95 GJ (0.90 MMBtu). Since there are no price or production figures for furniture, the increase in the cost of new steam per dollar output cannot be calculated.

TABLE 9-26. ECONOMIC IMPACT ANALYSIS SUMMARY -- INDUSTRIAL USERS

	Increase in product price[a,b]		Decrease in profit margin[a,c,d]		Range of capital availability ratios[e]	
Selected industries	Percent	Absolute ($/unit)	Net income (10^6 \$)	Return on assets	Debt coverage	Debt/equity
Furniture	NA[f]	NA[f]	NA[f]	NA[f]	5.99-5.88	0.37-0.38
Sawmill	0.58	0.00	0.02	0.29	7.38-7.33	0.49-0.49
Plywood	0.32	0.00	0.03	0.15	7.38-7.33	0.49-0.49
Paper	0.06	0.00	0.04	0.02	6.98-6.76	0.48-0.50
Sugar cane	0.38	0.00	0.08	0.09	4.54-3.16	0.29-0.40

[a]Represents difference between base case and Level II control.

[b]Assumes cost increases due to pollution control are passed on through higher prices.

[c]Assumes cost increases due to pollution control are fully absorbed.

[d]Represents changes at the model plant level.

[e]Range covers base case ratio with zero percent new debt financing to Level II control with 100 percent debt.

[f]Cannot be calculated because an average product price is not available in the furniture industry.

TABLE 9-27. MODEL FIRM AND PLANT CONFIGURATION -- FURNITURE MANUFACTURING INDUSTRY[a]

Model firm			
Financial data			
Average bond rating:	Baa		
Coverage ratio:	6.0		
Debt/equity ratio (%):	37.9		
Model plant			
Production data			
Plant output/year:	NA[b]		
Price/unit output:	NA		
Plant sales/year:	$5.0 million[c]		
Plant earnings/year:	$167.0 thousand[d]		
Boiler configuration			
Total firing rate:	26.4 MW (90 MMBtu/hr)		
Number of boilers:	3		
Characteristics of individual boilers	Boiler #		
	1	2	3
Capacity (MW [MMBtu/hr heat input])	8.8 (30)	8.8 (30)	8.8 (30)
Fuel type (base case)	Wood	Wood	Wood
Annual capacity utilization (%)	60	60	60
Replacement, expansion or existing	---Existing---		Replacement

[a]Based upon 1978 values.

[b]NA denotes not available.

[c]Based upon the average production of the firm most likely to invest in a new boiler.

[d]Based upon the 1978 return on sales ratio of 3.3 percent.

TABLE 9-28. BOILER COSTS -- FURNITURE MANUFACTURING INDUSTRY

Model boiler #	1a (base case)	1b	1e
Total boiler & pollution capital costs ($$10^6$)[a]	1.9	2.2	2.3
Annualized total boiler and pollution control cost $/GJ ($/MMBtu)[a]			
Capital	1.24 (1.31)	1.45 (1.53)	1.57 (1.66)
O&M[b]	4.17 (4.40)	4.44 (4.68)	4.48 (4.73)
Total	5.41 (5.71)	5.89 (6.21)	6.05 (6.39)
Control technology	MC	MC/WS	MC/ESP
PM emission rate ng/J (lb/MMBtu)	258.00 (0.60)	64.50 (0.15)	21.50 (0.05)

[a]1978 dollars.

[b]Includes general and administrative expenses, taxes, insurance, interest on working capital, and capital recovery. Assumes a 10.15 percent discount rate.

TABLE 9-29. CHANGE IN PRODUCT PRICE -- FURNITURE MANUFACTURING INDUSTRY

Model boiler #	1a (base case)	1b	1e
GJ Steam/unit output[a] (MMBtu steam/unit output)	0.95 (0.90)	0.95 (0.90)	0.95 (0.90)
Percent of new steam/ unit product[b]	33.3	33.3	33.3
Cost of new steam[c,d] ($/GJ [MMBtu])	5.41 (5.71)	5.89 (6.21)	6.05 (6.39)
Cost of new steam ($/ unit output)	1.71	1.87	1.92
Average product price/unit	NA	NA	NA
Percent increase in product price over the base case		NA	NA

[a]Estimated from industry contacts.

[b]Based on the model plant configuration, the new boiler represents one-third of total steam.

[c]Steam costs are from Chapter 8.

[d]1978 dollars.

Table 9-30 presents comparative coverage and debt/equity ratios for the selected control levels. The coverage ratio declined insignificantly from 5.99 to 5.88 over the five financing options and shows no significant difference between selected control levels. The debt/equity ratio increased from 0.37 to 0.38. Neither of these ratios suggest problems in obtaining capital for industry in any of the selected control options. The coverage ratios for all financing options fall above the 3.0 coverage benchmark.

9.2.2.4 Lumber Products Industry.

9.2.2.4.1 Sawmill industry.

Model plant description. The model firm and mill configuration for the sawmill industry is presented in Table 9-31. The model mill is one of two mills depicting the lumber products industry. The mill is assumed to be part of a 14 mill firm. Financial data are taken from Table 9-8 in Section 9.1 and are based on 1978 data.

This model is located in southern United States (Federal Region 4), the area of greatest potential growth for the lumber industry. The mill is run continuously throughout the year.

Total annual mill production is estimated at 30 to 40 million board feet which represents the average production for a 30 to 46 MMBtu bark boiler. Annual sales are $9.6 million and usually represent only one segment of a wood products company. Annual profits are 6.7 percent of sales or about $643,000.

A significant number of mills owned by large corporations may include an additional plywood or reconstituted board mill at the same site, sharing the steam produced. Data for this model mill represent only the sawmill operation. This mill accounts for 0.11 percent of the lumber market, based on production figures.

The model mill boiler house consists of two wood waste-fired boilers with a total heat input capacity of 17.6 MW (60 MMBtu). Model boiler #1, found in Section 6, is closest in size to the existing wood boiler in the sawmill industry at 80 percent capacity. Table 9-31 describes the individual boilers. The first boiler provides all the steam for the sawmill operation. The boiler investment decision is to replace this boiler with the second boiler of the same capacity. This boiler provides one half of total steam at the mill.

Selected control level results. The model plant replacement boiler is assumed to be a wood-fired boiler requiring PM control at all selected control levels. The two selected control levels are represented by model boiler #1b, which requires 97 percent PM reduction (64.5 ng/J [0.15 lb/MMBtu] ceiling) and model boiler #1e, which requires 99 percent PM reduction (21.5 ng/J [0.05 lb/MMBtu] ceiling).

Table 9-32 shows the pre-tax 1978 boiler and pollution control costs for the two selected control levels for the sawmill industry. Boiler and pollution control costs for the boiler investment range from about $1.9 million in the base case to $2.3 million in the 99 percent PM reduction level.

On the basis of these total steam costs, the cost of new steam per unit of output for the industry can be calculated. As can be seen in Table 9-33, the steam requirement per board foot is 0.0042 GJ (0.0040 MMBtu). Given an average price of $0.24/board foot, the increase in the cost of new steam per unit output for the 97 percent PM reduction level represents a 0.43 percent increase over the base case level, and a 0.58 percent increase for the 99 percent PM reduction level.

TABLE 9-30. CAPITAL AVAILABILITY INDICATORS --
FURNITURE MANUFACTURING INDUSTRY

Model boiler #	1a (base case)	1b	1e
Percent financed by debt	Coverage ratio		
0	5.99	5.99	5.99
25	5.97	5.96	5.96
50	5.95	5.94	5.93
75	5.93	5.91	5.91
100	5.91	5.89	5.88
Percent financed by debt	Debt-equity ratio		
0	0.37	0.37	0.37
25	0.37	0.37	0.37
50	0.37	0.37	0.38
75	0.38	0.38	0.38
100	0.38	0.38	0.38

TABLE 9-31. MODEL FIRM AND MILL CONFIGURATION--SAWMILL INDUSTRY[a]

Model firm		
Financial data		
Average bond rating:	Baa	
Coverage ratio:	7.4	
Debt/equity ratio (%):	48.7	
Model mill		
Production data		
Mill output/year:	40 million board feet[b]	
Price/unit output:	$0.24/board feet[c]	
Mill sales/year:	$9.6 million	
Mill earnings/year:	$643.0 thousand[d]	
Boiler configuration		
Total firing rate:	17.6 MW (60 MMBtu)	
Number of boilers:	2	
Characteristics of individual boilers		
	Boiler #	
	1	2
Capacity (MW [MMBtu/hr heat input])	8.8 (30)	8.8 (30)
Fuel type (base case)	Wood	Wood
Annual capacity utilization (%)	60	60
Replacement, expansion or existing	Existing	Replacement

[a]Based upon 1978 values.

[b]Based upon the average production of the firm most likely to invest in a new boiler.

[c]F.O.B. mill basis.

[d]Based upon the 1978 return on sales ratio of 6.7 percent.

TABLE 9-32. BOILER COSTS -- SAWMILL INDUSTRY

Model boiler #	1a (base case)	1b	1e
Total boiler & pollution control capital costs ($$10^6$)[a]	1.9	2.2	2.3
Annualized total boiler and pollution control cost $/GJ ($/MMBtu)[a]			
Capital	1.24 (1.31)	1.45 (1.53)	1.57 (1.66)
O&M[b]	4.17 (4.40)	4.44 (4.68)	4.48 (4.73)
Total	5.41 (5.71)	5.89 (6.21)	6.05 (6.39)
Control technology	MC	MC/WS	MC/ESP
PM emission rate			
ng/J	258.00	64.50	21.50
(lb/MMBtu)	(0.60)	(0.15)	(0.05)

[a]1978 dollars.

[b]Includes general and administrative expenses, taxes, insurance, interest on working capital, and capital recovery. Assumes a 10.15 discount rate.

TABLE 9-33. CHANGE IN PRODUCT PRICE -- SAWMILL INDUSTRY

Model boiler #	1a (base case)	1b	1e
GJ Steam/board foot output[a] (MMBtu steam/board foot output)	0.0042 (0.0040)	0.0042 (0.0040)	0.0042 (0.0040)
Percent of new steam/ board foot[b]	50	50	50
Cost of new steam ($/ GJ [MMBtu])[c,d]	5.41 (5.71)	5.89 (6.21)	6.05 (6.39)
Cost of new steam ($/ board foot output)[d]	0.0114	0.0124	0.0129
Average product price ($/ board foot)[d]	0.24	0.24	0.24
Cost of new steam ($/ $ output)	0.0475	0.0518	0.0533
Percent increase in product price over the base case		0.43	0.58
Absolute $ increase in product price over the base case		0.00	0.00

[a]Estimated from industry contacts.

[b]Based on model plant configuration, the new boiler represents one half of total steam.

[c]Steam costs are from Chapter 8.

[d]1978 dollars.

Table 9-34 illustrates the changes in profitability levels due to the new boiler investment. Given the negligible price effects, sales are assumed to be constant for all selected control levels and expenses increase only as a result of the new boiler investment. The decline in net income is almost three percent from the base case to the 97 percent PM reduction level and four percent from the base case to the 99 percent PM reduction level. The return on assets decreases by the same percentages as the decline in net profits.

Table 9-35 presents comparative coverage and debt/equity ratios for the selected control levels. The coverage ratio declined insignificantly from 7.4 to 7.3 under the five financing options and shows no significant difference between selected control levels. The debt/equity ratio remains around 0.5. Neither of these ratios suggest problems in obtaining capital for the industry in any of the selected control options.

The results of the analysis indicated that product price is expected to increase by at most 0.58 percent. New steam costs for the selected control levels comprise a relatively small portion of average product price. Profitability shows a slight decline as a result of the selected control levels when compared to the base case. The analysis of coverage ratios indicate that the new boiler investment can be funded totally by debt while still meeting the 3.0 coverage benchmark.

9.2.2.4.2 Plywood industry.

Model mill description. The major characteristics of the model mill are listed in Table 9-36. The mill is assumed to be part of a firm with seven plywood plants. Financial data are taken from Table 9-8 in Section 9.1 and are based on 1978 figures.

This model mill is located in southern United States (Federal Region 4). The mill is run almost continuously throughout the year. Total annual mill production is estimated at 90 million square feet. Annual sales are $19.8 million and profits are 6.70 percent of sales, or about $1.33 million. This mill accounts for approximately eight percent of the hardwood plywood market (concentrated in the southeastern United States) and 0.6 percent of the total plywood market.

The model mill boiler house consists of two wood waste-fired boilers and one gas and oil-fired boiler with total heat input capacity of 26.4 MW

TABLE 9-34. CHANGE IN PROFIT MARGIN DUE TO NEW BOILER INVESTMENT -- SAWMILL INDUSTRY (Mid-1978 $)

Model boiler #	1a (base case)[a]		1b		1e	
	10^6 $	% of sales	10^6 $	% of sales	10^6 $	% of sales
Sales/plant	9.02	100.00	9.02	100.00	9.02	100.00
Expenses[b]	7.90	87.65	7.93	87.92	7.95	88.14
Gross profit	1.12	12.39	1.09	12.08	1.07	11.86
Taxes	0.56	6.19	0.54	6.04	0.53	5.93
Net income	0.56	6.19	0.55	6.04	0.54	5.93
Return on assets (%)		6.46		6.28		6.17

[a]Base case assumes new boiler investment reflecting new annualized capital costs with no change in O&M costs.

[b]Incremental increase in expenses is based on percent increase in product price.

TABLE 9-35. CAPITAL AVAILABILITY INDICATORS -- SAWMILL INDUSTRY

Model boiler #	1a (base case)	1b	1e
Percent financed by debt	Coverage ratio		
0	7.38	7.37	7.37
25	7.37	7.36	7.36
50	7.37	7.35	7.35
75	7.36	7.34	7.34
100	7.35	7.33	7.33
Percent financed by debt	Debt-equity ratio		
0	0.49	0.49	0.49
25	0.49	0.49	0.49
50	0.49	0.49	0.49
75	0.49	0.49	0.49
100	0.49	0.49	0.49

TABLE 9-36. MODEL FIRM AND MILL CONFIGURATION--PLYWOOD INDUSTRY[a]

Model firm			
Financial data			
Average bond rating:	Baa		
Coverage ratio:	7.4		
Debt/equity ratio (%):	48.7		
Model mill			
Production data			
Mill output/year:	90 million square feet[b]		
Price/unit output:	$0.22/square foot[c]		
Mill sales year:	$19.8 million		
Mill earnings/year:	$1.3 million[d]		
Boiler configuration			
Total firing rate:	26.4 MW (90 MMBtu/hr)		
Number of boilers:	3		
Characteristics of individual boilers		Boiler #	
	1	2	3
Capacity (MW [MMBtu/hr heat input])	8.8 (30)	8.8 (30)	8.8 (30)
Fuel type (base case)	Wood	Natural gas/ fuel oil	Wood
Annual capacity utilization (%)	60	40	60
Replacement, expansion or existing	-------Existing------		Expansion

[a]Based upon 1978 values.

[b]Based upon the average production of the firm most likely to invest in a new boiler.

[c]F.O.B. mill basis.

[d]Based upon the 1978 return on sales ratio of 6.7 percent.

(90 MMBtu/hr). The model wood-fired boiler of 8.8 MW (30 MMBtu/hr) heat input is closest in size to the plywood industry's existing two boilers of 5.9 MW (20 MMBtu) at 60 and 40 percent annual capacity. Table 9-36 describes the individual boilers. The first boiler provides over 60 percent of the steam for the plywood mill. The independent plywood mill operation usually fires wood dust instead of bark, occasionally using natural gas for start-up or when wood is not available. The second boiler fires natural gas and fuel oil. All the steam generated is for process use. The boiler investment decision is to expand operations with a wood waste-fired boiler of the same capacity.

Selected control level results. The model plant replacement boiler is assumed to be a wood-fired boiler requiring PM control at all selected control levels. Table 9-37 shows the pre-tax 1978 boiler and pollution control costs for the two selected control levels for the plywood industry. The two selected control levels are represented by model boiler #1b, which requires 97 percent PM reduction (64.5 ng/J [0.15 lb/MMBtu] ceiling) and model boiler 1e, which requires 99 percent PM reduction (21.5 ng/J [0.05 lb/MMBtu] ceiling). Boiler and pollution control costs for the boiler investment range from about $1.9 million in the base case to $2.3 million in the 99 percent PM reduction level.

On the basis of these total steam costs the cost of new steam per unit of output for the industry can be calculated. As seen in Table 9-38, the steam requirement per square foot is 0.003 GJ (0.002 MMBtu). Given an average price of $0.22 per square foot, the increase in the cost of new steam per unit output for the 97 percent PM reduction level represents a 0.24 percent increase over the base case level and a 0.32 percent increase for the 99 percent PM reduction level.

Table 9-39 illustrates the changes in profitability levels due to the new boiler investment. Given the negligible price effects, sales are assumed to be constant for all selected control levels and expenses increase only as a result of the new boiler investment. The decline in net income is almost two percent from the base case to the 97 percent PM reduction level and nearly three percent from the base case to the 99 percent PM reduction level. The return on assets figures decrease by approximately the same percentages.

TABLE 9-37. BOILER COSTS -- PLYWOOD INDUSTRY

Model boiler #	1a (base case)	1b	1e
Total boiler & pollution control capital costs ($$10^6$)[a]	1.9	2.2	2.3
Annualized total boiler and pollution control cost $/GJ ($/MMBtu)[a]			
Capital	1.24 (1.31)	1.45 (1.53)	1.57 (1.66)
O&M[b]	4.17 (4.40)	4.44 (4.68)	4.48 (4.73)
Total	5.41 (5.71)	5.89 (6.21)	6.05 (6.39)
Control technology	MC	MC/WS	MC/ESP
PM emission rate			
ng/J	258.00	64.50	21.50
(lb/MMBtu)	(0.60)	(0.15)	(0.05)

[a]1978 dollars.

[b]Includes general and administrative expenses, taxes, insurance, interest on working capital, and capital recovery. Assumes a 10.15 discount rate.

TABLE 9-38. CHANGE IN PRODUCT PRICE -- PLYWOOD INDUSTRY

Model boiler #	1a (base case)	1b	1e
GJ (MMBtu) steam/square foot[a] (3/8") output	0.003 (0.002)	0.003 (0.002)	0.003 (0.002)
Percent of new steam/ square foot (3/8") product[b]	37.5	37.5	37.5
Cost of new steam ($/ GJ [MMBtu])[c,d]	5.41 (5.71)	5.89 (6.21)	6.05 (6.39)
Cost of new steam ($/square foot (3/8") output)[d]	0.0061	0.0066	0.0068
Average product price ($/ square foot [3/8"])[d]	0.22	0.22	0.22
Cost of new steam ($/ $ output)	0.0277	0.0301	0.0309
Percent increase in product price over the base case		0.24	0.32
Absolute $ increase in product price		0.00	0.00

[a]Estimated from industry contacts.

[b]Based on model plant configuration, the new boiler represents approximately 38 percent of total steam.

[c]Steam costs are from Chapter 8.

[d]1978 dollars.

TABLE 9-39. CHANGE IN PROFIT MARGIN DUE TO NEW BOILER INVESTMENT -- PLYWOOD INDUSTRY (Mid-1978 $)

Model boiler #	1a (base case)[a]		1b		1e	
	10^6 \$	% of sales	10^6 \$	% of sales	10^6 \$	% of sales
Sales/plant	18.61	100.00	18.61	100.00	18.61	100.00
Expenses[b]	16.22	87.14	16.25	87.32	16.27	87.25
Gross profit	2.40	12.86	2.36	12.68	2.34	12.75
Taxes	1.20	6.43	1.18	6.34	1.17	6.23
Net income	1.20	6.43	1.18	6.34	1.17	6.23
Return on assets (%)		6.68		6.58		6.53

[a]Base case assumes new boiler investment reflecting new annualized capital costs with no change in O&M costs.

[b]Incremental increase in expenses is based on percentage increase in product price.

Table 9-40 presents comparative coverage and debt/equity ratios for the selected control levels, which are the same as the sawmill industry. The coverage ratio declined insignificantly from 7.4 to 7.3 under the five financing options and shows no significant difference between selected control levels. The debt/equity ratio remains around 0.5. Neither of these ratios suggest problems in obtaining capital for the industry in any of the selected control options.

The results of the analysis indicated that product price is expected to increase by at most 0.32 percent. New steam costs for the selected control levels comprise a relatively small portion of average product price. Profitability shows a slight decline as a result of the selected control levels when compared to the base case. The analysis of coverage ratios indicate that the new boiler investment can be funded totally by debt while still meeting the 3.0 coverage benchmark.

9.2.2.5 Paper and Allied Products Manufacturing Industry

9.2.2.5.1 Model mill description. The model firm and mill configuration is presented in Table 9-41. The mill is assumed to be part of a 15 mill firm. Financial data are taken from Table 9-12 in Section 9.1 and are based on 1978 data.

This model mill is located in southern United States (Federal Region 4). The mill is run almost continually throughout the year. Total annual mill production is estimated at 280 thousand tons. Annual sales are $179 million and profits are 6.4 percent of sales or about $11.5 million. This mill accounts for approximately 1.0 percent of the paper market.

The model mill boiler house consists of two wood-fired boilers, one black liquor boiler and one fuel oil boiler with a total heat input capacity of 454 MW (1550 MMBtu/hr). Model boiler #4, found in Section 6, is closest in size to the paper industry's existing wood-fired boiler of 137 MW (536 MMBtu/hr) at 60 percent annual capacity utilization. Table 9-41 describes the individual boilers. The first boiler is a bark boiler. The investment decision is to purchase a new bark boiler, boiler #4, to expand present capacity. Boiler #2 is the recovery or black liquor boiler. Although black liquor is considered a waste product, this boiler is covered under the recovery boiler NSPS. The third boiler is a fuel oil standby boiler primarily used for start-up.

TABLE 9-40. CAPITAL AVAILABILITY INDICATORS -- PLYWOOD INDUSTRY

Model boiler #	1a (base case)	1b	1e
Percent financed by debt	Coverage ratio		
0	7.38	7.37	7.37
25	7.37	7.36	7.36
50	7.37	7.35	7.35
75	7.36	7.34	7.34
100	7.35	7.33	7.33
Percent financed by debt	Debt-equity ratio		
0	0.49	0.49	0.49
25	0.49	0.49	0.49
50	0.49	0.49	0.49
75	0.49	0.49	0.49
100	0.49	0.49	0.49

TABLE 9-41. MODEL FIRM AND MILL CONFIGURATION -- PAPER MANUFACTURING INDUSTRY[a]

Model firm				
Financial data				
Average bond rating:	Aa/Baa			
Coverage ratio:	7.0			
Debt/equity ratio (%):	48.8			
Model mill				
Production data				
Mill output/year:	280 thousand tons[b]			
Price/unit output:	$0.71/kg. ($.32/lb)			
Mill sales/year:	$179 million			
Mill earnings/year:	$11.5 million[c]			
Boiler configuration				
Total firing rate:	454 MW (1550 MMBtu/hr)			
Number of boilers:	4			
Characteristics of individual boilers	Boiler #			
	1	2	3	4
Capacity (MW [MMBtu/hr heat input])	117 (400)	176 (600)	44 (150)	117 (400)
Fuel type (base case)	Wood	Black liquor	Fuel oil	Wood
Annual capacity utilization (%)	60	100	0	60
Replacement, expansion or existing	--------Existing---------			Expansion

[a]Based upon 1978 values.

[b]Based upon the average production of the firm most likely to invest in a new boiler.

[c]Based upon the 1978 return on sales ratio of 6.4 percent.

Approximately 50-70 percent of total steam is generated from bark. In the winter months approximately 80 percent of all steam is generated for process use, 10 percent is for space heat, and 10 percent is for electricity generation. This mill generates 90 percent of its own electricity.

9.2.2.5.2 Selected control level results. The model plant replacement boiler is assumed to be a wood-fired boiler requiring PM control at all selected control levels. Table 9-42 shows the pre-tax 1978 boiler and pollution control costs for the two selected control levels for the paper industry. The two selected control levels are represented by model boiler #4b, which requires 97 percent PM reduction (64.5 ng/J [0.15 lb/MMBtu] ceiling) and model boiler #4e, which requires 99 percent PM reduction (21.5 ng/J [0.05 lb/MMBtu] ceiling). Boiler and pollution control costs for the boiler investment range from about $14.2 million in the base case to $16.1 million in the 99 percent PM reduction level.

On the basis of these total steam costs, the cost of new steam per unit of output for the industry, as can be seen in Table 9-43, can be calculated. The steam requirement of paper production per Kg (lb) is 0.02 GJ (0.01 MMBtu).

Given an average price of $0.71/Kg ($0.32/lb), the increase in the cost of new steam per dollar output for the 97 percent PM reduction level represents a 0.03 percent increase over the base case level and a 0.06 percent increase for the 99 percent PM reduction level.

Table 9-44 illustrates the changes in profitability levels due to the new boiler investment. Given the negligible price effects, sales are assumed to be constant for all selected control levels and expenses increase only as a result of the new boiler investment. The decline in net income is 0.20 percent from the base case to the 97 percent PM reduction level and 0.48 percent from the base case to the 99 percent PM reduction level.

Table 9-45 presents comparative coverage and debt/equity ratios for the selected control levels. The coverage ratio declined insignificantly from 6.98 to 6.76 under the five financing options and shows no significant difference between selected control levels. The debt/equity ratio increased from 0.48 to 0.50. Neither of these ratios suggest problems in obtaining capital for the industry in any of the selected control options.

The results of the analysis indicated that product price is expected to increase by at most 0.06 percent. New steam costs for the selected control levels comprise a relatively small portion of average produce price. Profitability shows a slight decline as a result of the selected control levels when compared to the base case. The analysis of coverage ratios indicate that the new boiler investment can be funded totally by debt while still meeting the 3.0 coverage benchmark.

9.2.2.6 Raw Sugar Cane Manufacturing Industry.

9.2.2.6.1 Model mill description. The major characteristics of the model firm are used in Table 9-46. Financial figures are taken from Table 9-16 in Section 9.1.

This model mill represents a large independent sugar milling operation in the southern United States (Federal Region 4). Total annual mill production of raw sugar is estimated at 181,406 megagrams (20,000 tons)/season. The milling season lasts for five months. Production of actual raw sugar, which is sugar ready to be sold or refined, is approximately 10.3 percent of total sugar cane production, or cane harvested specifically for use as sugar, not seed. The mill's market share in the industry is approximately seven percent of domestic raw sugar.

The price of raw sugar is $0.31/kilogram ($0.14/pound). Annual sales of raw sugar are $56 million and profits are 8.5 percent of sales, or about $4.7 million.

The model mill boiler house configuration consists of five bagasse-fired boilers with a total heat input capacity of 293 MW (1,000 MMBtu/hr). Model boiler #14, found in Section 6, is closest in size to the sugar cane industry's existing bagasse-fired boiler of 62 MW (210 MMBtu/hr) at 100 percent capacity utilization. This mill also has the capacity to begin production of related products, such as gasohol or sugar refining. Approximately 98 percent of total steam generated is for process use. The remaining two percent accounts for electricity generation. In this model mill, bagasse supplies 100 percent of total generated steam. Approximately 10,000 pounds of steam are required for one ton of sugar produced.

9.2.2.6.2 Selected control level results. The model plant replacement boiler is assumed to be a bagasse-fired boiler requiring PM control at all selected control levels. Table 9-47 shows the pre-tax 1978 boiler and

TABLE 9-42. BOILER COSTS -- PAPER MANUFACTURING INDUSTRY

Model boiler #	4a (base case)	4b	4e
Total boiler & pollution control capital costs ($\$10^6$)[a]	14.2	15.2	16.1
Annualized total boiler and pollution control cost \$/GJ (\$/MMBtu)[a]			
Capital	0.69 (0.73)	0.76 (0.80)	0.82 (0.86)
O&M[b]	1.51 (1.59)	1.63 (1.72)	1.59 (1.68)
Total	2.20 (2.32)	2.39 (2.52)	2.41 (2.54)
Control technology	MC	MC/WS	MC/ESP
PM emission rate ng/J (lb/MMBtu)	258.00 (0.60)	64.50 (0.15)	21.50 (0.05)

[a] 1978 dollars.

[b] Includes general and administrative expenses, taxes, insurance, interest on working capital, and capital recovery. Assumes a 10.15 discount rate.

TABLE 9-43. CHANGE IN PRODUCT PRICE -- PAPER MANUFACTURING INDUSTRY

Model boiler #	4a (Base Case)	4b	4e
GJ steam/kg output[a] (MMBtu steam/lb output)	0.02 (0.01)	0.02 (0.01)	0.02 (0.01)
Percent of new steam/ kg (lb) product[b]	27.3	27.3	27.3
Cost of new steam ($/ GJ [MMBtu])[c,d]	2.20 (2.32)	2.39 (2.52)	2.41 (2.54)
Cost of new steam ($/ kg (lb) output)[d]	0.0120 (0.0054)	0.0122 (0.0055)	0.0123 (0.0056)
Average product price ($/kg [lb])[d]	0.71 (0.32)	0.71 (0.32)	0.71 (0.32)
Cost of new steam ($/ $ output)	0.01690	0.01720	0.01734
Percent increase in product price		0.03	0.06
Absolute $ increase in product price/ kg (lb)		0.00 (0.00)	0.00 (0.00)

[a]Estimated from industry contacts.

[b]Based on model plant configuration, the new boiler represents approximately 27 percent of total steam.

[c]Steam costs are from Chapter 8.

[d]1978 dollars.

TABLE 9-44. CHANGE IN PROFIT MARGIN DUE TO NEW BOILER INVESTMENT -- PAPER MANUFACTURING INDUSTRY (Mid-1978 $)

Model boiler #	4a (base case)[a]		4b		4e	
	10^6 $	% of sales	10^6 $	% of sales	10^6 $	% of sales
Sales/plant	168.26	100.00	168.26	100.00	168.26	100.00
Expenses[b]	147.40	87.60	147.44	87.63	147.50	87.66
Gross profit	20.90	12.40	20.82	12.37	20.77	12.34
Taxes	10.43	6.20	10.41	6.19	10.40	6.17
Net income	10.43	6.20	10.41	6.19	10.39	6.17
Return on assets (%)		6.42		6.41		6.40

[a]Base case assumes new boiler investment reflecting new annualized capital costs with no change in O&M costs.

[b]Incremental increase in expenses is based on percentage increase in product price.

TABLE 9-45. CAPITAL AVAILABILITY INDICATORS -- PAPER MANUFACTURING INDUSTRY

Model boiler #	4a (base case)	4b	4e
Percent financed by debt	Coverage ratio		
0	6.98	6.98	6.98
25	6.93	6.93	6.93
50	6.88	6.88	6.87
75	6.83	6.82	6.81
100	6.78	6.77	6.76
Percent financed by debt	Debt-equity ratio		
0	0.48	0.48	0.48
25	0.49	0.49	0.49
50	0.49	0.49	0.49
75	0.50	0.50	0.50
100	0.50	0.50	0.50

TABLE 9-46. MODEL FIRM AND MILL CONFIGURATION -- SUGAR CANE MANUFACTURING INDUSTRY[a]

Model firm					
Financial data					
Average bond rating:	A/Baa				
Coverage ratio:	4.5				
Debt/equity ratio (%):	32.0				
Model mill					
Production data					
Mill output/year:[b]	181,406 megagrams (200,000 tons)[c]				
Price/unit output:	$0.31/kilogram ($0.14/pound wt.)				
Mill sales/year:	$56.0 million				
Mill earnings/year:	$4.7 million[d]				
Boiler configuration					
Total firing rate:	293 MW (1000 MMBtu/hr)				
Number of boilers:	5				
Characteristics of individual boilers	Boiler #				
	1	2	3	4	5
Capacity (MW [MMBtu/hr heat input])	58.6 (200)	58.6 (200)	58.6 (200)	58.6 (200)	58.6 (200)
Fuel type (base case)	Bagasse	Bagasse	Bagasse	Bagasse	Bagasse
Annual capacity utilization (%)	45	45	45	45	45
Replacement, expansion or existing	Existing	Existing	Existing	Existing	Replacement

[a]Based upon 1978 values.

[b]Based upon a five month average season.

[c]Based upon the average production of the firm most likely to invest in a new boiler.

[d]Based upon the 1978 return on sales of 8.5 percent.

TABLE 9-47. BOILER COSTS -- SUGAR CANE MANUFACTURING INDUSTRY

Model boiler #	15a (base case)	15b
Total boiler & pollution control capital costs ($$10^6$)[a]	5.9	6.5
Annualized total boiler and pollution control cost $/GJ ($/MMBtu)[a]		
Capital	0.82 (0.86)	0.93 (0.98)
O&M[b]	1.34 (1.41)	1.51 (1.59)
Total	2.16 (2.27)	2.44 (2.57)
Control technology	MC	WS
PM emission rate		
ng/J	267.00	86.00
(lb/MMBtu)	(0.62)	(0.20)

[a]1978 dollars.

[b]Includes general and administrative expenses, taxes, insurance, interest on working capital, and capital recovery. Assumes an 11 percent discount rate.

pollution control costs for the only selected control level for the sugar cane industry. Represented by model boiler #15b, the regulatory alternative requires 96 percent PM reduction (86.0 ng/J [0.20 lb/MMBtu] ceiling). Boiler and pollution control costs for the boiler investment range from about $5.9 million in the base case to $6.5 million in the 96 percent PM reduction level.

On the basis of these total steam costs the resultant cost of steam per unit of output for the industry, shown in Table 9-48, can be calculated. The steam requirement/Kg (lb) is 0.02 GJ (0.01 MMBtu). Given an average price of $0.31/Kg ($0.14/lb), the increase in the cost of new steam per unit output for the 96 percent PM reduction level represents a 0.38 percent increase over the base case level.

Table 9-49 illustrates the changes in profitability levels due to the new boiler investment. Given the negligible price effects, sales are assumed to be constant for all selected control levels and expenses increase only as a result of the new boiler investment. The decline in net income is almost two percent from the base case to the 97 percent PM reduction level. The return on assets figure only decreases by 1.9 percent from the base case to the control level.

Table 9- 50 presents comparative coverage and debt/equity ratios for the selected control levels. The coverage ratio declined from 4.54 to 3.16 under the five financing options, a relatively greater decrease than the other NFFB industries. The debt/equity ratio increased from 0.29 to 0.40. Neither of these ratios suggests problems in obtaining capital for the industry in any of the selected control options. Since these ratios show a low percentage of debt, future investments could be funded largely from debt depending upon the interest rate and the industry's inclination toward debt financing.

The coverage ratios for all financing options used for all of the selected control levels fall above the 3.0 coverage benchmark. The sugar cane industry, however, falls closest to this benchmark number than any of the NFFB industries. This ratio becomes 3.16 as can be seen in Table 9-50 under control level 15 with 100 percent debt financing.

The results of the analysis indicated that product price is expected to increase by at most 0.38 percent. Although the sugar cane industry is price sensitive, the alternative emission regulation produces an insignificant increase ($0.001) in product price per pound. New steam costs for the selected control levels comprise a relatively small portion of average product price. Profitability shows a slight decline as a result of the selected control levels when compared to the base case. The analysis of coverage ratios indicates that the new boiler investment can be funded totally by debt while still meeting the 3.0 coverage benchmark.

9.2.3 Impact on Selected Municipal Users

The following presents the economic impact associated with alternative control levels on selected municipal operators of NFFB's. This section outlines the methodology used to determine economic impact and discusses the potential impacts on the four selected municipalities.

9.2.3.1 Methodology of Economic Impact Analysis. The economic impact analysis of selected municipalities centers on the change in the cost of producing new steam and capital availability.

9.2.3.1.1 Cost of producing steam. In calculating the change in the cost of producing new steam, a twofold approach is used. First, the particular municipality's NFFB size is defined, and capital. operating, and maintenance costs are determined from the model boilers in Section 8. Second, capital costs are annualized using a discount rate relevant for each municipality and added to operating and maintenance costs and fuel costs, where applicable, to yield a total annualized cost per GJ (MMBtu) heat input under the base case and the selected control levels. Then, a percent change in these annualized costs over the base case is calculated.

9.2.3.1.2 Capital availability. Municipal resource recovery projects have been financed typically out of current revenues and long-term borrowings such as municipal and State revenue bonds, general obligation bonds, pollution control revenue bonds and Federal and State grants. No single financing source, however, supplies all resource recovery funds. In fact, more than one source can finance a single resource recovery plant and thereby spread out the costs and risks associated with the project.

The following briefly discusses some of the more popular methods of financing resource recovery projects:[55, 56]

- Current revenue capital financing. This method has been used often in waste disposal systems to finance small capital expenditures. However, current revenue financing depends upon

TABLE 9-48. CHANGE IN PRODUCT PRICE -- SUGAR CANE MANUFACTURING INDUSTRY

Model boiler #	15a (base case)	15b
GJ steam/kg output[a] (MMBtu steam/lb output)	0.02 (0.01)	0.02 (0.01)
Percent of new steam/ kg (lb) product[b]	20	20
Cost of new steam ($/ GJ [MMBtu])[c,d]	2.16 (2.27)	2.44 (2.57)
Cost of new steam ($/ kg (lb) output)[d]	0.0088 (0.0040)	0.0100 (0.0045)
Average product price ($/kg [lb])[d]	0.31 (0.14)	0.31 (0.14)
Cost of new steam ($/ $ output)	0.02838	0.03213
Percent increase in product price		0.38
Absolute $ increase in product price/ kg (lb)		0.00 (0.00)

[a]Estimated from industry contacts.

[b]Based on model plant configuration, the new boiler represents one fifth of total steam.

[c]Steam costs are from Chapter 8.

[d]1978 dollars.

TABLE 9-49. CHANGE IN PROFIT MARGIN DUE TO NEW BOILER INVESTMENT -- SUGAR CANE MANUFACTURING INDUSTRY (Mid-1978 $)

Model boiler #	15a (base case)[a]		15b	
	10^6 $	% of sales	10^6 $	% of sales
Sales/plant	52.64	100.00	52.64	100.00
Expenses[b]	44.20	83.97	44.37	84.29
Gross profit	8.44	16.03	8.27	15.71
Taxes	4.22	8.01	4.14	7.85
Net income	4.22	8.01	4.14	7.85
Return on assets (%)		4.70		4.61

[a]Base case assumes new boiler investment reflecting new annualized capital costs with no change in O&M costs.

[b]Incremental increase in expenses is based on increase in product price.

TABLE 9-50. CAPITAL AVAILABILITY INDICATORS -- SUGAR CANE MANUFACTURING INDUSTRY

Model boiler #	15a (base case)	15b
Percent financed by debt	Coverage ratio	
0	4.54	4.54
25	4.13	4.08
50	3.79	3.71
75	3.50	3.40
100	3.25	3.16
Percent financed by debt	Debt-equity ratio	
0	0.29	0.29
25	0.32	0.32
50	0.34	0.34
75	0.36	0.37
100	0.39	0.40

the ability of the local government to generate surplus funds. Municipalities that are implementing capital-intensive projects usually need to tap other sources of capital such as long-term borrowings or private company financing.

- <u>Public long-term borrowing -- general obligation bonds</u>. In this financing method the issuing municipality guarantees the general obligation bond with its "full faith and credit," that is, its ability to repay the principal and interest out of general tax revenues. In this type of bond financing, two requirements must usually be met: voters must approve the issue and municipal legal debt ceilings must not be exceeded. This bond issue does not require an economic or technical analysis of the particular project(s) to be financed. Oftentimes, groups of small projects are funded under one bond issue. General obligation bond financing is more economic when the debt issue exceeds $500,000 due to the transaction cost and its effect on the effective interest rate. Because they have a municipal guarantee and risk of default is lowest, these bonds carry the lowest interest rates of any municipal bonds.

- <u>Public long-term borrowing -- municipal revenue bonds</u>. This method of financing pledges the revenues generated from the project to guarantee repayment of the principal and interest. The general "faith and credit" of the municipality is not pledged and voter approval is not required. The bond's interest rate is a function of the revenue-generating capacity of the particular project and is usually higher due to greater risks than the rate for general obligation bonds. Revenue bond financing is economic when the debt issue is at least $1 million due to the transaction cost which helps determine the effective interest rate.

- <u>Private financing</u>. In this financing alternative, the municipality contracts a private firm to handle the resource recovery project. The firm then raises the capital to buy the equipment and operates the system. In this manner, the municipality does not need to allocate its own capital to operate the plant. Industrial revenue and pollution control revenue bonds are two examples of private financing.

The above illustrates that there are several ways to fund municipal resource recovery projects. If one financing source is infeasible, there are other sources that can be tapped.

In the following section, the capital availability issue discusses the ability to fund the incremental capital costs associated with the control levels. As it is assumed that the base case investment is affordable, only the question of funding the increment is addressed. The additional costs of complying with selected control levels is related to annual government expenditures, assuming a worse case whereby incremental funds could come from the annual budget. This ratio is calculated for publicly financed NFFB projects only.

9.2.3.2 Summary of Results. The selected municipality economic analysis of selected control levels indicates that no major economic impacts are expected. The percent change in annualized costs from the base case to Control Level II in no case exceeds 3.1 percent for the MSW-fired boilers and 5.4 percent for the 50 percent RDF/50 percent coal cofired boiler. The dollar change in annualized costs from the base case ranges from $10,000 (Level I) to $88,900 (Level II) for the MSW-fired boilers analyzed and $131,300 (Level I) to $222,700 (Level II) for the RDF/coal cofired boiler studied. Related to total government expenditures, these dollar increments are less than one percent. The capital availability analysis shows that no problems in financing the incremental capital costs are expected. The following sections explain these costs more fully.

The case studies discuss other factors that should be considered when evaluating potential economic impacts. The share of new NFFB's to the total number of boilers providing steam would reduce the overall percent change in annualized costs from the base case. Moreover, revenues received from selling steam would also reduce the effective costs. Savings incurred from not burning more expensive fossil fuels would also effectively reduce costs.

9.2.3.3 Albany, New York.

9.2.3.3.1 New NFFB configuration. As discussed in 9.1.2, Albany is in the process of building two new NFFB's. It is assumed that if the State of New York decided at a later date to replace an existing boiler or to expand with a new unit, the NFFB chosen would be similar in size to each NFFB presently being built. Model boiler #11, a 44 MW (150 MMBtu/hr) heat input RDF/coal cofired boiler, is closest in size and fuel to the actual facility's existing RDF boilers of 42.9 MW (144.8 MMBtu/hr) heat input each. Table 9-51 shows the basic configurations of a new NFFB. The existing boiler house was discussed in Section 9.1.2.

In the base case, all new NFFB's are subject to the applicable SIP emission regulation. Table 9-52 shows the capital, O&M and fuel costs associated with operating a new 44 MW (150 MMBtu/hr) heat input RDF/coal cofired boiler in the base case. Total annualized costs are \$4.99/GJ (\$5.27/MMBtu). However, by operating NFFB's, Albany is relying less on its oil-fired boilers, thereby reducing fuel oil expenses. The amount of the annual fuel savings would reduce the annualized cost of operating the new NFFB. These base case costs assume a PM emission limit of 138 ng/J (0.32 lb/MMBtu) for 94.5 percent control and an SO_2 ceiling of 1075 ng/J (2.5 lb/MMBtu) achieving 20 percent control.

9.2.3.3.2 Selected control level results. Table 9-52 also outlines the cost of a new boiler under the following more stringent pollution control scenarios relative to the base case: one, 97.4 percent PM control (64.5 ng/J [0.15 lb PM/MMBtu] limit) and 70 percent SO_2 control (405 ng/J [0.93 lb SO_2/MMBtu] ceiling); two, 97.4 percent PM control (64.5 ng/J [0.15 lb PM/MMBtu] limit) and 90 percent SO_2 control (135 ng/J [0.31 lb SO_2/MMBtu] ceiling); three, 99.1 percent PM control (21.5 ng/J [0.05 lb PM/MMBtu] ceiling) and 70 percent SO_2 control (405 ng/J [0.94 lb SO_2/MMBtu] limit); and four, 99.1 percent PM control (21.5 ng/J [0.05 lb PM/MMBtu] ceiling) and 90 percent SO_2 control (135 ng/J [0.31 lb SO_2/MMBtu] limit).

Capital availability to fund the incremental pollution control capital costs does not appear to pose a problem. In the base case, pollution control capital of \$1.8 million represents 14.2 percent of the total capital cost of \$12.8 million. In the most stringent control case, the capital cost of pollution control of \$2.6 million comprises 19.2 percent of the total capital cost of \$13.6 million. Assuming that the base case investment is affordable, the incremental capital cost due to the more stringent control level would add, at most, 5.8 percent to the total capital cost of the project. When compared to New York State appropriations which are financing the existing Albany NFFB's, this increment is too small to deem the project unaffordable.

As boiler costs do not change from base case to impact case, annualized boiler capital and O&M costs remain at \$4.15/GJ (\$4.38/MMBtu). Annualized pollution control capital and annual pollution control O&M, however, range from \$1.00/GJ (\$1.06/MMBtu) under a less stringent control case to \$1.11/GJ (\$1.17/MMBtu) under a more stringent control level for a total boiler and pollution control cost of from \$5.15/GJ (\$5.44/MMBtu) to \$5.26/GJ (\$5.55/MMBtu).

TABLE 9-51. NEW NFFB CONFIGURATION,[a] ALBANY, NEW YORK

Heat input capacity, MW (MMBtu/hr)	44 (150)
Fuel design type	RDF/coal[b]
Annual capacity utilization(%)	60

[a]Assumes new boiler configuration based on model boiler #11.

[b]High sulfur eastern coal. Fifty percent RDF/50 percent coal firing.

TABLE 9-52. BOILER AND POLLUTION CONTROL COSTS OF A 44 MW (150 MMBTU/HR) HEAT INPUT RDF/COAL BOILER (MODEL BOILER #11) ALBANY, NEW YORK (1978 10^3 $)

			Capital cost	Annualized capital charges[a]	Annual direct and indirect operating costs (incl. fuel)	Total Annualized costs	Total annualized costs/GJ (MMBtu)
Boiler[b]			10,955.7	1,280.1	2,174.9[c]	3,455.0	4.15 (4.38)
Pollution control[d]							
Level		Type					
PM	SO_2						
B	B	FGD-WS	1,816.5	268.2	434.7	702.9	0.84 (0.89)
I	I	FGD-WS	2,173.4	321.1	513.1	834.2	1.00 (1.06)
I	II	FGD-WS	2,233.1	330.2	537.1	867.3	1.04 (1.10)
II	I	ESP,FGD-WS	2,536.7	357.4	532.5	889.9	1.07 (1.13)
II	II	ESP,FGD-WS	2,609.3	368.4	557.2	925.6	1.11 (1.17)
Total boiler and pollution control							
Level							
PM	SO_2						
B	B		12,772.2	1,548.3	2,609.6	4,157.9	4.99 (5.27)
I	I		13,129.1	1,601.2	2,688.0	4,289.2	5.15 (5.44)
II	II		13,188.8	1,610.3	2,712.0	4,322.3	5.19 (5.48)
II	I		13,492.4	1,637.5	2,707.4	4,344.9	5.22 (5.51)
II	II		13,565.0	1,648.5	2,732.1	4,380.6	5.26 (5.55)

[a]Assumes an interest rate of 6 percent based upon a weighted average interest rate of New York State's bonded debt outstanding as stated in Moody's Municipal and Government Manual 1980.

[b]Boiler capital cost is annualized over a 30-year life.

[c]Transportation costs of $197,100 for coal and $137,970 for RDF are added to model boiler #11's fuel costs.

[d]FGD-WS capital costs are annualized over a 15-year life. The capital costs of ESP, FGD-WS, having different service lives, are annualized using weighing factors for 15- and 20-year lives.

Table 9-53 shows the change from the base case in the annualized cost of producing new steam. The range of changes in annualized cost is 3.2 to 5.4 percent. In dollar terms, the change from base case annualized costs ranges from $131,300 to $222,700. Relative to appropriations for State purposes of $3,652 million (see Section 9.1.2), the incremental amount is small. However, a new NFFB would be one of nine boilers at the Albany steam-producing plant. The percent change from the base case would then be reduced by the share of new steam from the NFFB to total steam generated at the plant. Therefore, the overall percent change in the cost of producing steam would be signfiicantly less than what Table 9-53 indicates.

It should be noted that Tables 9-52 and 9-53 present costs of a new NFFB that fires 50 percent coal and 50 percent RDF, while the actual Albany facilities will fire 100 percent RDF (refer to Table 9-20). Due to SO_2 controls, the costs for a cofired boiler are significantly higher than costs for a 100 percent RDF-fired unit which would not have SO_2 controls. However, the amount by which costs for the two NFFB's differ has not been determined. Therefore, Table 9-53 is overstating the actual percent change over the base case for a 100 percent RDF-fired facility.

9.2.3.4 Harrisburg, Pennsylvania.

9.2.3.4.1 New boiler house configuration. It is assumed that if Harrisburg replaced an existing boiler or expanded with a new unit, the NFFB chosen would be similar in size and fuel to each existing boiler. Model boiler #13, a 44 MW (150 MMBtu/hr) heat input MSW boiler, is nearest in size to the facility's existing MSW boilers of 42.8 MW (146 MMBtu/hr) heat input. The existing boiler house is outlined in Section 9.1.2. Table 9-54 shows the basic configurations of a new NFFB.

In the base case, the plant's boiler replacements are subject to existing SIP emission regulations. Table 9-55 outlines capital and O&M costs of a new 44 MW (150 MMBtu) heat input MSW boiler under the base case which specifies an ESP to achieve 92.9 percent PM control. Capital costs are annualized and added to O&M costs. To promote comparisons, these costs are then converted to a per GJ (MMBtu) basis.

9.2.3.4.2 Selected control level results. Table 9-55 delineates costs under two selected control levels: Level I using an ESP to achieve 95.5 percent PM control (43.0 ng/J [0.10 lb PM/MMBtu] ceiling); and Level

II employing an ESP to attain 98.5 percent PM control (21.5 ng/J [0.05 lb PM/MMBtu] limit). The annualized costs of these additional pollution controls range from $0.31/GJ ($0.33/MMBtu) to $0.35/GJ ($0.37/MMBtu); the total cost ranges from $1.82/GJ ($1.92/MMBtu) to $1.86/GJ ($1.96/MMBtu).

Capital availability to fund the incremental pollution control capital costs does not seem to pose a problem. In the base case pollution control capital of $1.1 million represents 6.3 percent of the total capital cost of $17.6 million. In the Level II control case the capital cost of pollution control is $1.3 million or 7.3 percent of the total capital cost of $17.8 million. Assuming that the base case investment is affordable, the incremental capital cost due to the control levels would add only 1.1 percent, at most, to the total capital cost of the project.

Table 9-56 depicts the annualized costs of producing steam under Levels I and II as opposed to the base case before and after accounting for a waste disposal credit. The cost of producing steam under Level I is 0.24 percent greater than under the base case before accounting for the credit and 1.10 percent greater after subtracting the credit. In Level II, achieving the most stringent pollution reductions, the cost of generating steam is 0.97 percent greater than in the base case without a landfill credit and 2.20 percent greater with a credit. However, a new NFFB would be one of three boilers at the Harrisburg steam plant. The percent change from the base case would then be reduced by the share of steam from the new NFFB to total steam generated at the plant. The overall change from the base case would be small.

In dollar terms, the change in annualized costs from the base case ranges from $10,000 in Level I to $33,200 in Level II. When compared to overall municipal expenditures of $15.4 million (see Section 9.1.2), these increments are less than one percent of the total. As a ratio of sewerage and sanitation expenditures of $2.7 million (see Section 9.1.2), this amount is less than three percent. However, it should be noted that higher costs of producing steam could be recovered partially from revenues generated from selling steam.

9.2.3.5 Peekskill, New York.

9.2.3.5.1 New NFFB configuration. Since the Peekskill plant is to be constructed by 1984 it could possibly show an impact under an alternative

TABLE 9-53. CHANGE IN ANNUALIZED COST OF PRODUCING STEAM ALBANY, NEW YORK, NFFB

	44 MW (150 MMBtu) RDF/coal cofired boiler (model boiler #11)	
	Cost/ GJ (MMBtu)	% Δ over base case
Base case PM and SO_2	4.99 (5.27)	--
Level I PM and SO_2	5.15 (5.44)	3.2
Level I PM, Level II SO_2	5.19 (5.48)	4.0
Level II PM, Level I SO_2	5.22 (5.51)	4.6
Level II PM and SO_2	5.26 (5.55)	5.4

TABLE 9-54. NEW NFFB CONFIGURATION,[a] HARRISBURG, PENNSYLVANIA

Heat input capacity, MW (MMBtu/hr)	44 (150)
Fuel design type	MSW
Annual capacity utilization (%)	60

[a]Assumes new boiler configuration based on model boilers.

TABLE 9-55 BOILER AND POLLUTION CONTROL COSTS OF A 44 MW (150 MMBTU/HR) HEAT INPUT MSW BOILER
(MODEL BOILER #13)
HARRISBURG, PENNSYLVANIA, NFFB
(1978 10^3 $)

		Capital cost	Annualized[a] capital charges	Annual direct and indirect operating costs (incl. fuel)	Total annualized costs[b]	Total annualized costs/GJ (MMBtu)[b]
Boiler[c]		16,500.0	2,011.9	1,148.0	1,245.9[d]	1.51 (1.59)[d]
Pollution control[e]						
PM level	Type					
B	ESP	1,112.9	151.8	108.8	260.6	0.31 (0.33)
I	ESP	1,168.7	159.2	111.4	270.6	0.33 (0.34)
II	ESP	1,298.2	176.9	116.9	293.8	0.35 (0.37)
Total boiler and pollution control						
Level						
B		17,612.9	1,163.7	1,256.8	1,506.5	1.82 (1.92)
I		17,668.7	2,171.1	1,259.4	1,516.5	1.84 (1.93)
II		17,798.2	2,188.8	1,264.9	1,539.7	1.86 (1.96)

[a] Assumes an interest rate of 7 percent based upon a weighted average interest rate on Harrisburg's bonded debt outstanding as delineated in Moody's Municipal and Government Manual 1980.

[b] Includes annualized capital costs, interest on working capital, general and administrative expenses, taxes and insurance.

[c] Boiler capital cost is annualized over a 30-year life.

[d] Includes waste disposal credit of $1,914,000 or $2.43/MMBtu.

[e] Pollution control capital costs are annualized over a 20-year life.

TABLE 9-56. CHANGE IN ANNUALIZED COST OF PRODUCING STEAM
HARRISBURG, PENNSYLVANIA NFFB

	44 MW (150 MMBtu/hr) MSW boiler (model boiler #13)			
	Cost/GJ (MMBtu) before landfill credit[a]	Net cost/ GJ (MMBtu)	%Δ over base case before landfill credit	Net %Δ over base case
Base case	4.11 (4.34)	1.82 (1.92)	--	--
Level I	4.12 (4.35)	1.84 (1.93)	0.24	1.10
Level II	4.15 (4.38)	1.86 (1.96)	0.97	2.20

[a]Landfill credit equals $2.43/MMBtu.

control level. Therefore, this analysis will present the costs of operating these 85.7 MW (292 MMBtu/hr) MSW boilers under the base case and Control Levels I and II. The costs of this boiler are determined by interpolating between model MSW boilers #13 of 44 MW (150 MMBtu/hr) and #14 of 117 MW (400 MMBtu/hr). Table 9-57 shows the basic configurations of the new NFFBs.

In the base case all new NFFB's are subject to the applicable SIP emission regulation. Table 9-58 depicts the capital and O&M costs associated with operating a new 86 MW (292 MMBtu/hr) heat input MSW boiler in the base case. Annualized capital and O&M costs associated with the boiler equal \$1.03/GJ (\$1.09/MMBtu), net of a landfill credit. Annualized pollution control (capital and O&M add another \$0.26/GJ (\$0.27/MMBtu) in the base case for a total annualized cost of \$1.29/GJ (\$1.36/MMBtu).

9.2.3.5.2 Selected control level results. Table 9-58 also outlines the costs of a new NFFB under two more stringent pollution control levels; Level I achieving 95.5 percent PM control (43.0 ng/J [0.10 lb PM/MMBtu] limit) and Level II attaining 98.5 percent control (21.5 ng/J [0.05 lb PM/MMBtu] limit). The annualized costs of these additional pollution controls range from \$0.27 per GJ (\$0.28/MMBtu) under Level I to \$0.30/GJ (\$0.31/MMBtu) under Level II for a total annualized cost ranging from \$1.30/GJ (\$1.37/MMBtu) to \$1.33/GJ (\$1.40/MMBtu).

Capital availability to fund the incremental pollution control capital costs does not seem to be a problem. In the base case pollution control capital cost of \$1.8 million for one boiler represents 6.2 percent of the total capital cost of \$29.5 million. The Level II capital cost of \$2.2 million represents 7.5 percent of the total capital cost of \$29.9 million. The incremental cost due to the control levels would add, at most, 1.4 percent to the total capital cost of each boiler. As discussed in Section 9.1.2, State, county, and municipal sources are planning to fund the NFFB's. The total financing package can be distributed, thereby rendering incremental costs affordable to any one party.

Table 9-59 shows how the costs of producing steam under the selected control levels differ from the base case before and after accounting for a waste disposal credit. Before subtracting the credit, the cost of producing steam under the first control level is 0.28 percent greater than the base case, while the cost under the second control level is 1.40 percent greater. After subtracting the credit, the net cost of producing new steam under Level I is 0.78 percent greater than the base case, while the net cost under Level II is 3.10 percent greater. In dollar terms this change from the base case ranges from $20,600 to $72,200 for each boiler. It should be noted that increased costs due to the standard could be recouped in part through revenues generated from selling steam.

A comparison can be made between the increment in total annualized costs and expenditures on the municipal, county, and State levels. All three levels are considered because the exact shares of each level in financing the NFFB project are uncertain. When compared to total 1977 municipal expenditures of $7.3 million (inflated to 1978 terms), these increments represent less than one percent of the total. However, as a ratio of 1977 municipal sewerage and sanitation expenditures of $0.4 million (inflated to 1978 terms), the increment ranges from 3.0 percent in Level I to 15.0 percent in Level II. Comparing the increment to total county and to State expenditures would show an even smaller ratio.

9.2.3.6 Saugus, Massachusetts.

9.2.3.6.1 New boiler house configuration. It is possible that RESCO will operate a third boiler.[57] As alternative waste disposal costs climb, more communities may find dumping at the Saugus facility to be economically sound. This higher volume of recoverable refuse coupled with the likelihood of selling more steam to local industry could make a third boiler investment financially attractive. Therefore this analysis will evaluate the costs of operating a new unit configured similar to the existing units. RESCO is considering installing a new 680 megagrams/day (750 tons/day) unit with a heat input capacity of 89.4 MW (305 MMBtu/hr). The costs of this boiler are determined by interpolating between model MSW boilers #13 of 44 MW (150 MMBtu/hr) and #14 of 117 MW (400 MMBtu/hr). Table 9-60 shows the basic configurations of the new NFFB.

In the base case all new NFFB's are subject to the applicable SIP emission regulation. Table 9-61 shows the capital and O&M costs associated with operating a new 89 MW (305 MMBtu/hr) heat input MSW boiler in the base case. Annualized boiler capital and O&M costs net of a landfill credit equal $1.55/GJ ($1.63/MMBtu). Annualized pollution control capital and O&M

TABLE 9-57 NEW NFFB CONFIGURATION
PEEKSKILL, NEW YORK

	Boiler #1	Boiler #2
Heat input capacity, MW (MMBtu/hr)[a]	85.7 (292)	85.7 (292)
Fuel design type	MSW	MSW
Annual capacity utilization (%)	60	60

[a]Costs for this boiler size are derived by interpolating between the MSW model boiler #13 (44 MW [150 MMBtu/hr]) and the MSW model boiler #14 (117 MW [400 MMBtu/hr]).

TABLE 9-58. BOILER AND POLLUTION CONTROL COSTS OF A 86 MW (292 MMBTU/HR) HEAT INPUT MSW BOILER[a]
PEEKSKILL, NEW YORK
(1978 10^3 $)

		Capital cost	Annualized[b,c] capital charges	Annual direct and indirect operating costs (incl. fuel)	Total annualized costs	Total annualized costs/GJ (MMBtu)
Boiler[d]		27,656.7	3,159.7	2,230.1	1,675.7[e]	1.03 (1.09)[e]
Pollution control[f]						
PM level	Type					
B	ESP	1,836.1	237.0	174.2	411.2	0.26 (0.27)
I	ESP	1,922.8	248.2	183.5	431.8	0.27 (0.28)
II	ESP	2,243.5	289.3	194.2	483.4	0.30 (0.31)
Total boiler and pollution control						
Level						
B		29,492.8	3,396.7	2,404.3	2.086.9	1.29 (1.36)
I		29,579.5	3,407.9	2,413.6	2,107.5	1.30 (1.37)
II		29,900.2	3,449.0	2,424.3	2,159.1	1.33 (1.40)

[a]Costs for this boiler size are interpolated from model boilers #13 (44 MW [150 MMBtu/hr MSW]) and #14 (117 MW [400 MMBtu/hr MSW]).

[b]Assumes a 6 percent interest rate.

[c]Includes annualized capital costs, interest on working capital, general and administrative expenses, taxes and insurance.

[d]Boiler capital costs annualized over a 30-year life.

[e]Includes waste disposal credit of 3,714,100 or $2.42/MMBtu.

[f]Pollution control capital costs annualized over a 20-year life.

TABLE 9-59. CHANGE IN ANNUALIZED COST OF PRODUCING STEAM
PEEKSKILL, NEW YORK, NFFB

	Cost/GJ (MMBtu) before landfill credit[a]	Net cost/ GJ (MMBtu)	% Δ over base case before landfill credit	Net % Δ over base case
86 MW (292 MMBtu/hr) MSW boiler[b]				
Base case	3.58 (3.78)	1.29 (1.36)	--	--
Level I	3.59 (3.79)	1.30 (1.37)	0.28	0.78
Level II	3.63 (3.83)	1.33 (1.40)	1.40	3.10

[a]Landfill credit equals $2.42/MMBtu.

[b]Costs are derived by interpolating between the MSW model boilers #13 (44 MW [150 MMBtu/hr]) and #14 (117 MW [400 MMBtu/hr]).

TABLE 9-60. NEW NFFB CONFIGURATION
SAUGUS, MASSACHUSETTS

Heat input capacity,[a] MW (MMBtu/hr)	89.4 (305)
Fuel design type	MSW
Annual capacity utilization (%)	60

[a]Costs for this boiler size will be derived by interpolating between the MSW model boiler # 13 (44 MW [150 MMBtu/hr]) and the MSW model boiler #14 (117 MW [400 MMBtu/hr]).

TABLE 9-61. BOILER AND POLLUTION CONTROL COSTS OF A 89 MW (305 MMBTU/HR) MSW BOILER[a]
SAUGUS, MASSACHUSETTS
(1978 10^3 $)

		Capital cost	Annualized[b,c] capital charges	Annual direct and indirect operating costs (incl. fuel)	Total annualized costs	Total annualized costs/GJ (MMBtu)
Boiler[d]		28,599.1	4,182.8	2,314.2	2,617.4[e]	1.55 (1.63)[e]
Pollution control[f]						
PM level	Type					
B	ESP	1,897.2	302.4	180.4	482.7	0.29 (0.30)
I	ESP	1,986.4	316.7	190.0	506.7	0.30 (0.32)
II	ESP	2,325.4	370.3	201.2	571.6	0.34 (0.36)
Total boiler and pollution control						
Level						
B		30,496.3	4,485.2	2,494.6	3,100.1	1.83 (1.93)
I		30,585.5	4,499.5	2,504.2	3,124.1	1.85 (1.95)
II		30,924.5	4,553.1	2,515.4	3,189.0	1.89 (1.99)

[a]Costs for this boiler size interpolated from the MSW model boilers #13 (44 MW (150 MMBtu/hr)) and #14 (400 MMBtu/hr).

[b]Assumes an interest rate of 10 percent.

[c]Includes annualized capital costs, interest on working capital, general and administrative expenses, taxes, and insurance.

[d]Boiler capital costs annualized over a 30-year life.

[e]Includes landfill credit of $3,879,500 or $2.42/MMBtu.

[f]Pollution control capital costs annualized over a 20-year life.

costs add another \$0.29/GJ (\$0.30/MMBtu) for a total boiler and pollution control cost of \$1.83/GJ (\$1.93/MMBtu).

9.2.3.6.2 Selected control level results. Table 9-61 shows the cost of a new NFFB under two more stringent pollution control options: one level using an ESP to attain 95.5 percent PM control (43.0 ng/J [0.10 lb PM/MMBtu] ceiling) and another level operating an ESP to achieve 98.5 percent PM control (21.5 ng/J [0.05 lb PM/MMBtu] limit).

In the base case, pollution control capital costs of \$1.9 million represents 6.2 percent of the total capital cost of \$30.5 million. In the most expensive pollution control option (Level II), pollution control capital costs of \$2.3 million comprises 7.5 percent of the total capital cost of \$30.9 million. The incremental capital cost due to the control levels would add, at most, 1.4 percent to the total capital cost of the NFFB project. Since it is assumed that the base case investment is affordable, the 1.4 percent maximum increase in capital costs due to the more stringent control level appears equally affordable. Furthermore, any increase in costs could be recouped from revenues generated from selling steam.

Table 9-62 shows how the costs of producing new steam under the selected control levels differ from the base case. The cost of producing steam under the first selected control level is 0.49 percent greater than the base case before subtracting a landfill credit and 1.09 percent greater after subtracting the credit. The second control level is 1.46 percent greater than the base case without the credit and 3.28 with the credit. In dollar terms this change from the base case ranges from \$24,000 to \$88,900. A new NFFB would be one of three boilers operated at the RESCO steam plant. The percent change from the base case would then be reduced by the share of steam from the new boiler to steam from the entire plant. The overall change from the base case would thereby be reduced.

TABLE 9-62. CHANGE IN ANNUALIZED COST OF PRODUCING STEAM, SAUGUS, MASSACHUSETTS NFFB

	Cost/GJ (MMBtu) before landfill credit[a]	Net cost/ GJ (MMBtu)	% Δ over base case before landfill credit	Net % Δ over base case
89 MW heat input (305 MMBtu/hr) MSW Boiler[b]				
Base case	4.12 (4.35)	1.83 (1.93)	--	--
Level I	4.14 (4.37)	1.85 (1.95)	0.49	1.09
Level II	4.18 (4.41)	1.89 (1.99)	1.46	3.28

[a]Landfill credit equals $2.42/MMBtu.

[b]Costs for this boiler size are derived by interpolating between MSW model boilers #13 (44 MW [150 MMBtu/hr]) and #14 (117 MW [400 MMBtu/hr]).

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APPENDIX A - EVOLUTION OF THE PROPOSED STANDARDS

A screening study of nonfossil fuel fired boilers was begun on August 31, 1978 by Acurex Corporation under the direction of the Office of Air Quality Planning and Standards (OAQPS), Emission Standards and Engineering Division (ESED). The screening study was concluded in February 1979, with the recommendation that New Source Performance Standards be developed for nonfossil fuel fired boilers. Work then began on Phase II of the study. Radian Corporation took over the project in February 1980.

The chronology which follows lists important events which have occurred in the development of this background information document for New Source Performance Standards for nonfossil fuel fired boilers.

DATE	ACTIVITY
July 28, 1978	Meeting with DuPont Company representatives
December 7, 1978	Visit to Resource Energy Systems Company in Saugus, Massachusetts
January 4, 1979	Visit to Weyerhaeuser Company pulp mill in New Bern, North Carolina
January 10, 1979	Visit to National Center for Resource Recovery in Washington, D.C.
April 19, 1979	Visit to General Electric in Erie, Pennsylvania
June 4, 1979	Visit to Westvaco paper mill in Covington, Virginia
June 5, 1979	Visit to Owens-Illinois paper mill in Big Island, Virginia
June 12, 1979	Visit to Long Lake Lumber Company sawmill in Spokane, Washington
June 13, 1979	Visit to Georgia-Pacific pulp & paper mill in Bellingham, Washington
June 13, 1979	Visit to Weyerhaeuser Company sawmill in Snoqualmie Falls, Washington
June 14, 1979	Visit to Simpson Timber Company sawmill in Shelton, Washington
June 22, 1979	Visit to Union Camp pulp and paper mill in Franklin, Virginia
June 26, 1979	Visit to Nashville Thermal Transfer Corporation in Nashville, Tennessee
June 27, 1979	Visit to municipal incinerator in Salem, Virginia
July 12, 1979	Meeting with Council of Industrial Boiler Owners representatives
July 25, 1979	Visit to General Motors Corporation in Pontiac, Michigan

DATE	ACTIVITY
July 26, 1979	Meeting with R.E. Frounfelker of Systems Technology Corporation
August 22, 1979	Survey of small municipal incinerators completed
September 5, 1979	Meeting with American Plywood Association representatives
September 13, 1979	Visit to Champion International paper mill in Roanoke Rapids, North Carolina
September 17, 1979	Visit to U.S. Sugar Corporation mill in Pahokee, Florida
September 18, 1979	Visit to St. Regis Paper Company paper mill in Jacksonville, Florida
September 19, 1979	Visit to St. Joe Paper Company paper mill in Port St. Joe, Florida
November 5-7, 1979	Emission testing visit to municipal incinerator in Salem, Virginia
December 10-15, 1979	Emission testing visit to Owens-Illinois paper mill in Big Island, Virginia
December 17-19, 1979	Emission testing visit to U.S. Sugar Corporation mill in Pahokee, Florida
December 21, 1979	Section 114 letters sent to industries
January 9, 1980	Meeting with Chemical Manufacturers Association representatives
January 16-24, 1980	Emission testing visit to St. Joe Paper Company paper mill in Port St. Joe, Florida
January 29-31, 1980	Emission testing visit to St. Regis Paper Company mill in Jacksonville, Florida
February 12-13, 1980	Emission testing visit to Westvaco pulp and paper mill in Covington, Virginia
March 11, 1980	Meeting with Florida Sugar Cane League representatives

DATE	ACTIVITY
March 25, 1980	Visit to Gulf & Western Food Products Company in South Bay, Florida
March 25, 1980	Visit to Sugar Cane Growers Cooperative of Florida in Belle Glade, Florida
March 25, 1980	Visit to Atlantic Sugar Association in Belle Glade, Florida
June 23-27, 1980	Emission testing visit to St. Regis Paper Company paper mill in Jacksonville, Florida
July 29, 1980	Meeting with National Council of the Paper Industry for Air and Stream Improvement
August 28, 1980	Visit to Owens-Illinois paper mill in Big Island, Virginia
September 22-26, 1980	Emission testing visit to Owens-Illinois paper mill in Big Island, Virginia
October 7, 1980	Visit to Georgia-Pacific Corporation in Bellingham, Washington
October 8, 1980	Visit to Weyerhaeuser Company in Longview, Washington
October 9, 1980	Visit to Long Lake Lumber Company in Spokane, Washington
November 7, 1980	Opacity testing visit to Nashville Thermal Transfer Corporation in Nashville, Tennessee
November 10, 1980	Opacity testing visit to Georgia-Pacific Corporation in Emporia, Virginia
November 11, 1980	Opacity testing visit to Champion International Corporation in Corrigan, Texas
November 12, 1980	Opacity testing visit to Georgia-Pacific Corporation in Warm Springs, Virginia
November 14, 1980	Meeting with Hawaii Sugar Planters Association representatives
November 17, 1980	Meeting with D. Junge, Director of the Energy Research & Development Institute at Oregon State University

DATE	ACTIVITY
November 17-22, 1980	Emission testing visit to Georgia-Pacific pulp & paper mill in Bellingham, Washington
December 8-12, 1980	Emission testing visit to Weyerhaeuser Company in Longview, Washington
December 15-19, 1980	Emission testing visit to Long Lake Lumber Company in Spokane, Washington
January 19, 1981	Opacity testing visit to Champion International paper mill in Roanoke Rapids, North Carolina
January 21, 1981	Opacity testing visit to Research Energy Systems Company in Saugus, Massachusetts
February 10, 1981	Meeting with representatives of Weyerhaeuser Company to discuss test data from the ELECTROSCRUBBER filter.
June 2, 1981	Meeting with representatives of the American Boiler Manufacturers' Association
July 14, 1981	Meeting with representatives of the National Council of the Paper Industry for Air and Stream Improvement
February 9, 1982	Meeting with representatives of the National Council of the Paper Industry for Air and Steam Improvement, the Council of Industrial Boiler Owners, the American Boiler Manufacturers' Association and the Chemical Manufacturers' Association.

APPENDIX B

INDEX TO ENVIRONMENTAL CONSIDERATIONS

This appendix consists of a reference system which is cross indexed with the October 21, 1974, _Federal Register_ (30 FR 37419) containing EPA guidelines for the preparation of Environmental Impact Statements. This index can be used to identify sections of the document which contain data and information germane to any portion of the _Federal Register_ guidelines.

There are, however, other documents and docket entries which also contain data and information, of both a policy and a technical nature, used in developing the proposed standards. This appendix specifies only the portions of this document that are relevant to the indexed items.

TABLE B-1. INDEX TO ENVIRONMENTAL CONSIDERATIONS

Agency Guideline for Preparing Regulatory Action Environmental Impact Statements (39 FR 37419)	Location Within the Background Information Document
(1) Background and summary of regulatory alternatives	
Regulatory alternatives	The regulatory alternatives are summarized in Chapter 6.
Statutory basis for proposing standards	The statutory basis for the proposed standards is summarized in Chapter 2, Section 2.1.
Source category and affected industries	A discussion of the nonfossil fuel fired boiler source category is presented in Chapter 3. Details of the "business/economic" nature of the industries affected are presented in Chapter 9.
Emission control technologies	A discussion of emission control technologies is presented in Chapter 4.

TABLE B-1. (CONTINUED)

Agency Guideline for Preparing Regulatory Action Environmental Impact Statements (39 FR 37419)	Locations Within the Background Information Document
(2) Environmental, Energy, and Economic Impacts of Regulatory Alternatives	
Regulatory alternatives	Various regulatory alternatives are discussed in Chapter 6.
Environmental impacts (Individual boilers)	The environmental impacts of various regulatory alternatives are presented in Chapter 7, Sections 7.1, 7.2 and 7.3.
Energy impacts (Individual boilers)	The energy impacts of various regulatory alternatives are discussed in Chapter 7, Section 7.4
Cost impacts (Individual boilers)	Cost impacts of various regulatory alternatives are discussed in Chapter 8.
Economic impacts (Individual boilers)	The economic impacts of various regulatory alternatives are presented in Chapter 9.
National Environmental and energy impacts	The national Environmental and energy impacts of regulatory alternatives are presented in Chapter 7.
National and regional cost impacts	The national and regional cost impacts of regulatory alternatives are presented in Chapters 8 and 9.

TABLE B-1. (CONTINUED)

Agency Guideline for Preparing Regulatory Action Environmental Impact Statements (39 FR 37419)	Location Within the Background Information Document
(3) Environmental impact of the regulatory alternatives	
Air pollution (Individual boilers)	The impact of the proposed standards on air pollution is presented in Chapter 7, Section 7.1.
Water pollution (Individual boilers)	The impact of the proposed standards on water pollution is presented in Chapter 7, Section 7.2.
Solid waste disposal (Individual boilers)	The impact of the proposed standards on solid waste disposal is presented in Chapter 7, Section 7.3.

APPENDIX C

Available emission data illustrating the performance levels achievable by various control systems evaluated in this study are presented in this appendix. The data are analyzed and discussed in Chapter 4. The data base is organized as follows:

Section C.1 - Particulate Emission Data

Section C.2 - Visible Emission Data

Section C.3 - SO_2 Emission Data

Section C.4 - References

For each data set presented in this Appendix, a brief description of the test site is provided which includes data (when available) such as:

- Boiler type and rated capacity
- Boiler load factor during testing
- Type of emission control system
- Emission control system design specifications
- Emission control system operating parameters during testing
- Emission control system outlet emission level

All particulate and visible emission test sites are given a letter designation (example, Plant AB). All SO_2 emission test sites are given a roman numeral designation (example, Location I).

C.1 PARTICULATE EMISSION DATA

A majority of the particulate emission data presented here was obtained from industry sources or from State and local air pollution control agencies. Other tests were conducted by nonfossil fuel fired boiler owners/operators or by the EPA.

Because the test data came from many different sources, a set of test review criteria were developed in order to insure only valid test data would be used in this study. A discussion of these criteria follows.

The first part of these criteria was to insure the test was conducted in accordance with EPA Method 5 procedures. All the emission test data (with one exception discussed below) obtained for this study were submitted to the Emissions Measurement Branch (EMB) of EPA and reviewed to determine that Method 5 procedures were followed. Tests with insufficient documentation to show that proper procedures were followed, or tests which showed deviations from Method 5 procedures which could have significantly affected the test results, were not used in NSPS development and are not presented in this document. One additional emission test was accepted for this study without EMB review. There was insufficient documentation with this test which prevented a complete review; however, this test was performed under EPA supervision and therefore proper Method 5 procedures were assumed to have been followed.

The second part of the test review consisted of determining the critical design and operation parameters of the boiler and emission control system. These minimum design and operation parameters required were as follows:

- boiler firing method and rated steam capacity
- fuel type(s) fired during testing
- boiler load during testing
- control device operation parameters during testing such as pressure drop for wet scrubbers, air-to-cloth ratio of fabric filters, and specific collection area for electrostatic precipitators.

Any emission test performed on a boiler and control system for which the above data were unavailable was not used in this study or presented in this document.

Finally, the design and operation of the boiler and control system were reviewed to determine if there were design deficiencies or examples of improper operation during testing which could have affected the control device performance. If design or operation problems were found the test was generally not used in this study or presented in this document. However, the test was used if sufficient data were available (such as control device inlet emission data) to show that the control device was still able to achieve the design removal efficiency under these conditions. The exception to this is testing done by EPA specifically for this study. All the data from EPA emission tests done for this study are presented in Appendix C. However, if the results are not considered representative of well designed and operated systems, the EPA data are not presented in Chapter 4 and are not used in NSPS development.

Each site is given a letter designation according to the fuel type. The fuel type is indicated by the first letter (A or B for wood, D for bagasse, F for MSW, and H for RDF). Cofired boilers are listed with other plants firing the same nonfossil fuel. Each site is briefly described and is followed by a presentation of the test data.

The site descriptions include boiler type and rated capacity. The type of particulate control equipment is also identified. Since these tests were conducted by different individuals, some of the tests have more detailed information on the control devices, fuel, and test conditions than others.

A test summary sheet follows each site description. Date, percent isokinetic, boiler load, and sample point location during testing are presented. Stack gas data presented include: flow rate, temperature, and percent moisture, oxygen, and carbon dioxide. Information is also presented concerning control equipment type and important operating parameters. Only the control equipment through which the flue gas has passed is listed. For example, if the sampling location is at the inlet to a wet scrubber, the control equipment listed may include a mechanical collector but not the wet scrubber. Fuel analyses are included when available.

The particulate emissions expressed in ng/J (lb/million Btu) were determined by the following procedure:

$$E = CF\ [20.9 - \text{percent } O_2)]$$

where:

(1) E = pollutant emission ng/J (lb/million Btu).

(2) C = pollutant concentration, ng/dscm (lb/dscf).

(3) Percent O_2 = oxygen content by volume (expressed as percent), dry basis.

(4) F = a factor representing a ratio of the volume of dry flue gases generated to the calorific value of the fuel combusted.

The following F factors were used in this report.

(i) For bark F = 2.589 x 10^{-7} dscm/J (9,640 dscf/million Btu). For wood residue other than bark F = 2.492 x 10^{-7} dscm/J (9,280 dscf/million Btu). For hogged wood F = 2.524 x 10^{-7} dscm/J (9,400 dscf/million Btu).

(ii) For municipal solid waste (MSW) F = 2.589 x 10^{-7} dscm/J (9,640 dscf/million Btu).

(iii) For refuse derived fuel (RDF) F = 2.551 x 10^{-7} dscm/J (9,500 dscf/million Btu).

(iv) For bagasse F = 2.479 x 10^{-7} dscm/J (9,230 dscf/million Btu).

(v) For coal F = 2.627 x 10^{-7} dscm/J (9,780 dscf/million Btu).

(vi) For oil F = 2.476 x 10^{-7} dscm/J (9,220 dscf/million Btu).

For facilities firing combinations of fossil fuels and nonfossil fuels, the F factor was determined with the applicable formula as follows:

$$F = \sum_{i=1}^{n} X_i F_i$$

where:

X_i = the fraction of total heat input derived from each type of fuel (e.g. fuel oil, bituminous coal, wood residue, etc.)

F_i = the applicable F factor for each fuel type.

n = the number of fuels being burned in combination.

Since the F factor does not vary considerably for the fuels considered in this report, the use of generalized factors such as those shown above introduce little error into the analysis. However, if a fuel analysis is known, the F factor (dscm/J or dscf/million Btu) on a dry basis may be calculated more precisely as follows.

$$F = \frac{10^{-6}[227.2(\%H) + 95.5(\%C) + 35.6(\%S) + 8.7(\%N) - 28.7(\%O)}{GCV}$$

(SI units)

$$F = \frac{10^{6}[3.64(\%H) + 1.53(\%C) + 0.57(\%S) + 0.14(\%N) \quad 0.46(\%O)]}{GCV}$$

(English units)

(i) H, C, S, N, and O are content by weight of hydrogen, carbon, sulfur, nitrogen, and oxygen (expressed as percent), respectively, as determined on the same basis as GCV by ultimate analysis of the fuel fired, using A.S.T.M. method D3178-74 or D3176 (solid fuels), or computed from results using A.S.T.M. methods D1137-53(70), D1945-64(73), or D1946-67(72) (gaseous fuels) as applicable.

(ii) GCV is the gross calorific value (kJ/kg, Btu/lb) of the fuel combusted, determined by the A.S.T.M. test methods D201566(72) for solid fuels and D1826-64(70) for gaseous fuels as applicable.

(iii) For facilities which fire both fossil fuels and nonfossil fuels, the F value is based on the total heat input of all fuels fired.

This section is organized as follows:

Section C.1.1 - Wood-Fired Boilers and Wood/Fossil Fuel Cofired Boilers

Section C.1.2 - Bagasse-Fired Boilers

Section C.1.3 - MSW-Fired Boilers

Section C.1.4 - RDF-Fired Boilers and RDF/Fossil Fuel Cofired Boilers

C.1.1 Wood-Fired Boilers and Wood/Fossil Fuel Cofired Boilers

The following facility descriptions and particulate emission data are for wood-fired and wood/fossil fuel cofired boilers. Each site is given a 2-letter plant designation beginning with the letter A or B. This letter indicates the facility has a wood-fired boiler or a wood/fossil fuel boiler. A number after the plant designation distinguishes between different tests at the same plant.

PLANT AA[1-5]

An emissions test was performed on the No. 5 boiler at plant AA to determine if it was in compliance with the State of Washington emission standards. The No. 5 boiler is a traveling grate spreader stoker boiler rated at 150,000 pounds per hour of steam. The boiler uses hog fuel of which no more than 5 percent comes from wood stored in salt water. The fuel ash content varies from 2 to 8 percent (dry basis). The fuel moisture content is 50-55 percent in the summer and 60-65 percent in winter. The species of wood fired are hemlock, fir, and spruce.

A mechanical collector and wet scrubber in series are used for particulate emission control. The flue gas from the boiler passes through the air heater, the mechanical collector, and the wet scrubber.

The wet scrubber is a variable throat venturi with a demister. The fly ash collected by the mechanical collector passes through a sand classifier and the large fraction is reinjected into the boiler furnace.

Two EPA Method 5 test runs were performed. The boiler operated at an average of 95 percent of rated capacity. The scrubber pressure drop during testing was 18 inches of water. The average particulate emissions were 0.048 pounds per million Btu which is less than the State allowable emissions level of 0.093 pounds per million Btu.

PLANT AA[1]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	11/7/79	11/7/79	___	
% Isokinetic	98.5	100.4	___	
Boiler Load (% of design)	95	95	___	95
Sample Point Location	Outlet of scrubber			
Stack Gas Data				
Flow (Nm^3/s-dry)	37.2	26.4	___	31.8
Flow (dscfm)	78,910	56,070	___	67,490
Temperature (°C)	66	62	___	64
Temperature (°F)	151	144	___	148
Moisture (%)	25.4	21.8	___	23.6
Oxygen, dry (%)	7.3	7.3	___	7.3
CO_2, dry (%)	13.7	13.7	___	13.7
Particulate Emissions				
g/Nm^3-dry	0.0595	0.0458		0.0526
g/Nm^3-dry @ 12% CO_2	0.0526	0.0412	___	0.0469
gr/dscf	0.026	0.020	___	0.023
gr/dscf @ 12% CO_2	0.023	0.018	___	0.020
ng/J	23.2	17.8	___	20.5
lb/10^6 Btu	0.054	0.0413	___	0.0477
Average Opacity	___	___	___	___
Control Device				
Type	MC/WS			
Operating Parameter[1]	___	___	___	18
Design Parameter[1]	___			
Design Flow Rate (ACFM)	___			

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT AB[6-10]

An emission test was run at plant AB to determine compliance with the Oregon particulate emission standard. The boiler is a spreader stoker rated at 70,000 pounds per hour of steam. The primary fuel is a hogged wood/bark mixture of douglas fir and hemlock. This wood fuel is size classified and only the pieces too large for the feed system are hogged. This results in a larger average fuel particle size than if all the fuel was hogged. The secondary fuels are hardboard wastes, consisting of pulverized fiber dust and sanderdust which are burned in a separate sanderdust burner in the boiler. The estimated moisture content of the combined fuels is 45 percent. Particulate emissions are controlled by a mechanical collector followed by an impingement wet scrubber. Fly ash collected by the mechanical collector passes through a sand classifier and large particles are reinjected into the boiler furnace. The normal operating scrubber pressure drop is 6 to 8 inches of water.

Three EPA Method 5 test runs were made on both the inlet and outlet to the wet scrubber. The third test run was done while firing a fuel with higher fines and moisture contents than normal. The excess air rate was also higher on the third test run than on the first two runs. These factors caused the particulate loading at the scrubber inlet to be higher during the third test run, although there was no significant increase in emissions from the scrubber outlet. Average emissions were 0.0678 pounds per million Btu, which was within the allowable emission rate of 0.21 pounds per million Btu. The boiler operated at an average of 79 percent of rated capacity during the test. The scrubber pressure drop during testing was normal.

PLANT AB1[6]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	3/28/78	3/28/78	3/28/78	
% Isokinetic	108.9	106.8	97.2	
Boiler Load (% of design)	79	79	79	79
Sample Point Location	Inlet of scrubber			
Stack Gas Data				
Flow (Nm^3/s-dry)	7.4	7.8	10.0	8.4
Flow (dscfm)	15,600	16,600	21,100	17,800
Temperature (°C)	196.7	195.0	196.1	195.9
Temperature (°F)	386	383	385	385
Moisture (%)	17.2	15.6	19.6	17.5
Oxygen, dry (%)	7.0	7.4	*10.2	8.2
CO_2, dry (%)	12.7	12.2	9.8	11.6
Particulate Emissions				
g/Nm^3-dry	0.249	0.247	0.382	0.293
g/Nm^3-dry @ 12% CO_2	0.236	0.242	0.467	0.315
gr/dscf	0.109	0.108	0.167	0.128
gr/dscf @ 12% CO_2	0.103	0.106	0.204	0.138
ng/J	101.0	96.5	188.3	128.6
lb/10^6 Btu	0.235	0.2245	0.438	0.2992
Average Opacity				
Control Device				
Type	MC			
Operating Parameter[1]				
Design Parameter[1]				
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

*Estimated

PLANT AB2[6]

TEST SUMMARY SHEETS
(Particulates only)

Test Number	One	Two	Three	Average
General Data				
Date	3/28/78	3/28/78	3/28/78	
% Isokinetic	102.5	100.4	95.4	
Boiler Load (% of design)	79	79	79	79
Sample Point Location	Outlet of scrubber			
Stack Gas Data				
Flow (Nm^3/s-dry)	7.4	7.8	10.2	13.2
Flow (dscfm)	15,600	16,600	15,650	15,950
Temperature (°C)	75	72	69	72
Temperature (°F)	167	161	157	162
Moisture (%)	22.3	20.4	22.4	21.7
Oxygen, dry (%)	8.2	8.4	12.0	9.5
CO_2, dry (%)	11.4	11.2	8.8	10.5
Particulate Emissions				
g/Nm^3-dry	0.073	0.0549	0.0572	0.0617
g/Nm^3-dry @ 12% CO_2	0.0778	0.0595	0.0778	0.0717
gr/dscf	0.032	0.024	0.025	0.027
gr/dscf @ 12% CO_2	0.034	0.026	0.034	0.031
ng/J	30.4	23.2	33.9	29.2
lb/10^6 Btu	0.0707	0.0539	0.0788	0.0678
Average Opacity				
Control Device				
Type	MC/WS			
Operating Parameter[1]				6-8
Design Parameter[1]				
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT AC[11,12]

Plant AC was tested by the operator to determine the particulate emission rate. Two sets of tests were performed, one on the combined flue gases from boilers No.1 and 2 and one on boiler No.3. Boilers No.1 and 2 are identical wood-fired spreader stokers, each rated at 37,000 pounds per hour of steam. Their flue gases pass through individual mechanical collectors and then are sent to a common impingement wet scrubber and exhausted through a common stack. Boiler No.3 is a wood-fired spreader stoker rated at 55,000 pounds per hour of steam. Boiler No. 3 is also controlled with a mechanical collector and an impingement wet scrubber. The normal operating pressure drop for both scrubbers is 6 to 8 inches of water. Fly ash collected by the mechanical collectors is not reinjected.

Three EPA Method 5 test runs were made on each wet scrubber outlet. The boiler load on No.s 1 and 2 averaged 63 percent of rated capacity. The load on boiler No.3 averaged 47 percent of rated capacity. During the test, the boilers burned 20 percent wood trim and 80 percent bark. The emission rate for boilers No.1 and 2 averaged 0.182 pounds per million Btu. The particulate emission rate for boiler No.3 averaged 0.170 pounds per million Btu. The scrubber pressure drop during the tests was normal.

PLANT AC1[11]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	12/17/78	12/17/78	12/17/78	
% Isokinetic	100.6	99.4	98.1	
Boiler Load (% of design)	72	61	56	63
Sample Point Location	Outlet of scrubber - 1 & 2			
Stack Gas Data				
Flow (Nm^3/s-dry)	9.0	8.9	9.3	9.1
Flow (dscfm)	19,100	18,800	19,700	19,200
Temperature (°C)	63.9	66.1	66.7	65.6
Temperature (°F)	147	151	152	150
Moisture (%)	20.3	18.2	17.3	18.6
Oxygen, dry (%)	10.0	12.3	13.5	11.9
CO_2, dry (%)	10.5	8.2	7.0	8.6
Particulate Emissions				
g/Nm^3-dry	0.229	0.114	0.069	0.137
g/Nm^3-dry @ 12% CO_2	0.252	0.160	0.114	0.175
gr/dscf	0.1	0.05	0.03	0.06
gr/dscf @ 12% CO_2	0.11	0.07	0.05	0.08
ng/J	113.1	71.4	49.9	78.1
$lb/10^6$ Btu	0.263	0.166	0.116	0.182
Average Opacity				20
Control Device				
Type	MC/WS			
Operating Parameter[1]				6-8
Design Parameter[1]				
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT AC2[11]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	12/17/78	12/17/78	12/17/78	
% Isokinetic	100.5	104.2	103.7	
Boiler Load (% of design)	44	48	48	47
Sample Point Location	Outlet of scrubber - 3			
Stack Gas Data				
Flow (Nm^3/s-dry)	7.5	7.5	7.3	7.4
Flow (dscfm)	16,000	15,800	15,400	15,700
Temperature (°C)	75.6	77.2	76.7	76.5
Temperature (°F)	168	171	170	170
Moisture (%)	19.5	22.8	22.1	21.5
Oxygen, dry (%)	12.5	12.5	12.5	12.5
CO_2, dry (%)	8.0	8.1	8.0	8.0
Particulate Emissions				
g/Nm^3-dry	0.137	0.092	0.114	0.114
g/Nm^3-dry @ 12% CO_2	0.206	0.135	0.172	0.171
gr/dscf	0.06	0.04	0.05	0.05
gr/dscf @ 12% CO_2	0.09	0.059	0.075	0.075
ng/J	87.7	58.5	73.1	73.1
$lb/10^6$ Btu	0.204	0.136	0.170	0.170
Average Opacity				< 20
Control Device				
Type	MC/WS			
Operating Parameter[1]				6-8
Design Parameter[1]				
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT AD[12,13]

Plant AD was tested by the operator to determine the particulate emission rate. Plant AD has a spreader stoker boiler rated at 40,000 pounds per hour of steam. The boiler has a mechanical collector and a venturi wet scrubber. The normal operating scrubber pressure drop is 6 to 8 inches of water. All of the fly ash collected by the mechanical collector is reinjected into the boiler furnace.

Three EPA Method 5 test runs were conducted. During the test the wood fuel was 90 percent bark and 10 percent wood trim. The particulate emissions averaged 0.182 pounds per million Btu. The scrubber pressure drop during the tests was normal. The steam meter was not working so an exact steam flow rate could not be determined but it was reported by plant personnel as normal. Based on the mass emission rate and the F-factor, the estimated boiler operating rate is below 75 percent capacity. The steam flow rate is calculated to be approximately 27,000 to 32,300 pounds per hour.

PLANT AD1[13]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	12/19/78	12/19/78	12/19/78	
% Isokinetic	96.1	100.8	101.0	
Boiler Load (% of design)	*68	*70	*80	*73
Sample Point Location	Outlet of scrubber			
Stack Gas Data				
Flow (Nm^3/s-dry)	8.3	7.9	7.8	7.9
Flow (dscfm)	17,500	16,700	16,500	16,700
Temperature (°C)	60.0	63.9	66.7	63.5
Temperature (°F)	140	147	152	146
Moisture (%)	18.2	23.3	23.0	21.5
Oxygen, dry (%)	12.3	11.6	10.5	11.5
CO_2, dry (%)	8.2	9.0	10.0	9.1
Particulate Emissions				
g/Nm^3-dry	0.114	0.137	0.160	0.137
g/Nm^3-dry @ 12% CO_2	0.160	0.183	0.183	0.175
gr/dscf	0.05	0.06	0.07	0.06
gr/dscf @ 12% CO_2	0.07	0.08	0.08	0.08
ng/J	71.8	80.0	83.4	78.4
$lb/10^6$ Btu	0.167	0.186	0.194	0.182
Average Opacity				10
Control Device				
Type	MC/WS			
Operating Parameter[1]				
Design Parameter[1]				6-8
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.
*Estimated, based on mass emission rate and F-factor.

PLANT AE[12,14]

Plant AE was tested by the operator to determine the particulate emission rate. The plant has a wood-fired spreader stoker rated at 120,000 pounds per hour of steam. Particulate emissions are controlled by a mechanical collector and a venturi wet scrubber in series. The normal operating scrubber pressure drop is 6 to 8 inches of water. Fly ash collected by the mechanical collector passes through a sand classifier and large particles are reinjected into the boiler furnace.

Three EPA Method 5 test runs were made. The wood fuel during testing was 80 percent bark and 20 percent sawdust and wood trim. The boiler operated at 85 percent of rated capacity during the test. The average particulate emissions were 0.131 pounds per million Btu. The scrubber pressure drop during the test was normal.

PLANT AE1[14]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	11/28/78	11/28/78	11/28/78	
% Isokinetic	104.6	105.2	104.6	
Boiler Load (% of design)	92	88	74	85
Sample Point Location	Outlet of scrubber			
Stack Gas Data				
Flow (Nm^3/s-dry)	19.6	18.9	17.2	18.5
Flow (dscfm)	41,500	40,000	36,400	39,300
Temperature (°C)	55.0	56.1	55.6	55.6
Temperature (°F)	131	133	132	132
Moisture (%)	16.7	18.2	18.4	17.8
Oxygen, dry (%)	8.3	8.7	10.3	9.1
CO_2, dry (%)	12.1	11.8	10.2	11.4
Particulate Emissions				
g/Nm^3-dry	0.092	0.137	0.137	0.122
g/Nm^3-dry @ 12% CO_2	0.092	0.137	0.160	0.130
gr/dscf	0.04	0.06	0.06	0.05
gr/dscf @ 12% CO_2	0.04	0.06	0.07	0.06
ng/J	39.1	60.6	69.7	56.5
lb/10^6 Btu	0.091	0.141	0.162	0.131
Average Opacity				15
Control Device				
Type	MC/WS			
Operating Parameter[1]				6-8
Design Parameter[1]				
Design Flow Rate (ACFM)				

[1] For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM. For FF, A/C = ft/min.

PLANT AF[12,15,16]

Plant AF was tested by the operator to determine the particulate emission rate. This plant has a wood-fired spreader stoker rated at 120,000 pounds per hour of steam. Particulate emissions are controlled by a mechanical collector followed by an impingement wet scrubber. The normal operating scrubber pressure drop is 6 to 8 inches of water. Fly ash collected by the mechanical collector passes through a sand classifier and large particles are reinjected into the boiler furnace.

Three EPA Method 5 test runs were made. During the test the boiler averaged 72 percent of rated capacity. The wood fuel was 90 percent bark and 10 percent wood trim. The particulate emissions averaged 0.100 pounds per million Btu. The scrubber pressure drop during the test was normal.

PLANT AFI[15]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	1/10/79	1/10/79	1/10/79	
% Isokinetic	105.2	101.5	100.8	
Boiler Load (% of design)	71	71	75	72
Sample Point Location	Outlet of scrubber			
Stack Gas Data				
Flow (Nm^3/s-dry)	12.2	12.1	12.2	12.2
Flow (dscfm)	25,800	25,600	25,900	25,800
Temperature (°C)	63.9	63.9	63.9	63.9
Temperature (°F)	147	147	147	147
Moisture (%)	19.9	20.3	19.7	20.0
Oxygen, dry (%)	7.8	7.6	7.4	7.6
CO_2, dry (%)	12.7	12.9	13.2	12.9
Particulate Emissions				
g/Nm^3-dry	0.07	0.14	0.11	0.11
g/Nm^3-dry @ 12% CO_2	0.065	0.13	0.10	0.10
gr/dscf	0.03	0.06	0.05	0.05
gr/dscf @ 12% CO_2	0.03	0.06	0.05	0.05
ng/J	28.0	55.9	45.6	43.2
lb/10^6 Btu	0.065	0.13	0.106	0.100
Average Opacity				15
Control Device				
Type	MC/WS			
Operating Parameter[1]				6-8
Design Parameter[1]				
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT AG[12,17]

Plant AG was tested by its operator to determine the particulate emission rate. The plant has a wood-fired spreader stoker boiler rated at 110,000 pounds per hour of steam. The particulate emissions from the boiler are controlled by a mechanical collector followed by a venturi wet scrubber. The normal operating scrubber pressure drop is 6 to 8 inches of water. Fly ash collected by the mechanical collector passes through a sand classifier and large particles are reinjected into the boiler furnace.

Three EPA Method 5 test runs were made. The boiler operated at an average of 103 percent of rated capacity during the test. The wood fuel during the test was 90 percent bark and 10 percent sawdust. The average particulate emissions were 0.169 pounds per million Btu. The scrubber pressure drop during the test was normal.

PLANT AG1[17]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	10/31/78	10/31/78	10/31/78	
% Isokinetic	99.1	103.6	100.0	
Boiler Load (% of design)	104	101	103	103
Sample Point Location	Outlet of scrubber			
Stack Gas Data				
Flow (Nm^3/s-dry)	18.6	17.5	18.2	18.1
Flow (dscfm)	39,400	37,100	38,600	38,400
Temperature (°C)	60.0	57.2	55.0	57.4
Temperature (°F)	140	135	131	135
Moisture (%)	15.5	16.1	16.2	15.9
Oxygen, dry (%)	8.1	7.2	7.8	7.7
CO_2, dry (%)	12.5	13.5	12.8	12.9
Particulate Emissions				
g/Nm^3-dry	0.137	0.206	0.21	0.184
g/Nm^3-dry @ 12% CO_2	0.132	0.18	0.18	0.164
gr/dscf	0.06	0.09	0.09	0.08
gr/dscf @ 12% CO_2	0.06	0.08	0.08	0.07
ng/J	56.8	79.1	82.6	72.8
$lb/10^6$ Btu	0.132	0.184	0.192	0.169
Average Opacity				10
Control Device				
Type	MC/WS			
Operating Parameter[1]				6-8
Design Parameter[1]				
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT AH[12,18]

Plant AH was tested by the operator to determine the particulate emission rate. This plant has a wood-fired spreader stoker rated at 140,000 pounds per hour of steam. The particulate emissions are controlled by a mechanical collector followed by a venturi wet scrubber. The normal operating scrubber pressure drop is 6 to 8 inches of water. Fly ash collected by the mechanical collector passes through a sand classifier and large particles are reinjected into the boiler furnace.

Three EPA Method 5 test runs were made. The average boiler load during testing was 65 percent of rated capacity. The wood fuel was 85 percent bark and 15 percent wood trim. The average particulate emission rate was 0.148 pounds per million Btu. The scrubber pressure drop during the test was normal.

PLANT AH1[18]

TEST SUMMARY SHEETS
(Particulates only)

Test Number	One	Two	Three	Average
General Data				
Date	11/14/78	11/14/78	11/14/78	
% Isokinetic	106.6	102.2	104.1	
Boiler Load (% of design)	66	64	66	65
Sample Point Location	Outlet of scrubber			
Stack Gas Data				
Flow (Nm^3/s-dry)	12.2	13.0	13.0	12.7
Flow (dscfm)	25,800	27,600	27,500	27,000
Temperature (°C)	62.8	64.4	65.0	64.1
Temperature (°F)	145	148	149	147
Moisture (%)	20.6	16.8	18.4	18.6
Oxygen, dry (%)	7.5	8.4	8.8	8.2
CO_2, dry (%)	13.0	12.1	11.7	12.3
Particulate Emissions				
g/Nm^3-dry	0.183	0.092	0.19	0.16
g/Nm^3-dry @ 12% CO_2	0.169	0.092	0.19	0.15
gr/dscf	0.08	0.04	0.08	0.07
gr/dscf @ 12% CO_2	0.074	0.04	0.082	0.07
ng/J	72.2	38.7	80.0	63.6
lb/10^6 Btu	0.168	0.090	0.186	0.148
Average Opacity				20
Control Device				
Type	MC/WS			
Operating Parameter[1]				6-8
Design Parameter[1]				
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT AI[12,16,19]

Plant AI was tested to determine compliance with North Carolina particulate emissions standards. This plant has a wood-fired spreader stoker boiler rated at 110,000 pounds per hour of steam. Particulate emissions are controlled by a mechanical collector followed by a venturi wet scrubber. The normal operating scrubber pressure drop is 6 to 8 inches of water. Fly ash collected by the mechanical collector passes through a sand classifier and large particles are reinjected into the boiler furnace.

Three EPA Method 5 test runs were made. The average boiler load during testing was 86 percent of rated capacity. The wood fuel fired was sawdust and pulverized wood residue. The average particulate emissions were 0.212 pounds per million Btu. This was below the State allowable emissions of 0.34 pounds per million Btu. The scrubber pressure drop during testing was normal.

PLANT AI1[19]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	6/30/79	6/30/79	6/30/79	
% Isokinetic	89	90.8	93.6	
Boiler Load (% of design)	91	91	77	86
Sample Point Location	Outlet of scrubber			
Stack Gas Data				
Flow (Nm^3/s-dry)	18.7	18.4	16.3	17.8
Flow (dscfm)	39,700	39,100	34,600	37,800
Temperature (°C)	51.1	55.0	58.3	54.8
Temperature (°F)	124	131	137	131
Moisture (%)	10.8	12.4	13.4	12.2
Oxygen, dry (%)	10.8	9.5	12.5	10.9
CO_2, dry (%)	7.9	9.7	7.7	8.4
Particulate Emissions				
g/Nm^3-dry	0.233	0.096	0.172	0.167
g/Nm^3-dry @ 12% CO_2	0.359	0.117	0.270	0.249
gr/dscf	0.102	0.042	0.075	0.073
gr/dscf @ 12% CO_2	0.157	0.051	0.118	0.109
ng/J	122.6	43.9	107.1	91.2
lb/10^6 Btu	0.285	0.102	0.249	0.212
Average Opacity				
Control Device				
Type	MC/WS			
Operating Parameter[1]				6-8
Design Parameter[1]				
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT AJ[20,21,22]

Plant AJ was tested to determine compliance with Florida particulate emission standards and later by the EPA as a part of the standards development program. The plant has a wood-fired spreader stoker boiler rated at 110,000 pounds per hour of steam. The wood fuel is fired at 90 percent bark and 10 percent sawdust on the average. Particulate emissions are controlled by a mechanical collector followed by a variable throat venturi wet scrubber. Fly ash collected by the mechanical collector passes through a sand classifier and the larger particles are reinjected into the boiler furnace. The normal scrubber pressure drop is 8 to 10 inches of water.

One test (AJ5) was conducted in July 1978 to determine compliance with Florida particulate emissions standards. During this test, the average boiler load was 91 percent of rated capacity. The average particulate emissions at the scrubber outlet were 0.057 pounds per million Btu which was less than the allowable emissions of 0.3 pounds per million Btu. The scrubber pressure drop was 15.2 inches of water.

Two additional EPA method 5 tests were performed by the EPA during January 1980. Each test consisted of 3 simultaneous test runs at the inlet (AJ1 and AJ3) and outlet (AJ2 and AJ4) of the wet scrubber. The scrubber pressure drop during testing was 8 inches of water for the first test and 13.5 inches of water for the second test.

During test AJ5 the measured excess air level at the scrubber outlet was 70 percent, but during the two EPA tests the measured excess air level ranged from 150 to 300 percent. Based on this information, this boiler was being operated at excess air levels much higher than those required for proper operation during the EPA tests. As discussed in Chapters 3 and 4, the higher excess air levels would tend to increase uncontrolled emissions. Also, if the design gas flow through the mechanical collector was exceeded, the mechanical collector efficiency would be reduced well below design levels. Both of these factors could cause an increase in emissions at the scrubber inlet. During the EPA tests, the scrubber design inlet grain loading of 0.42 gr/dscf was exceeded on four of the six test runs.

Though apparently the scrubber removal efficiency was not adversely affected by the higher inlet emissions, the scrubber outlet emissions would still be higher than would be expected if inlet emissions had been at the proper levels. Therefore these outlet emissions would not be representative of the emissions expected from a venturi scrubber with a pressure drop of 8 to 13.5 inches applied to a well designed and operated wood-fired boiler.

The inlet emissions for the EPA tests (AJ1 and AJ3), are not shown in Chapter 4 because the orsat analyses were questionable. This prevents an accurate conversion of grain loading (gr/dscf) to mass per unit heat input. (pounds per million Btu). The outlet emissions are shown in section 4.1.6 but not in section 4.5 due to the operation problems previously discussed.

For tests AJ1, AJ2, AJ3, and AJ4, the fuel analyses were as follows:[1]

Test AJ1/AJ2:	Run 1	Run 2	Run 3
% H_2O	48.51	48.04	48.54
% Ash_d	0.92	1.23	4.47
% S_d	0.04	0.03	0.02
% N_d	0.15	0.10	0.14
HHV_d(Btu/lb)	9,280	9,490	9,040
HHV_d(kJ/kg)	21,600	22,070	21,020

Test AJ3/AJ4:	Run 1	Run 2	Run 3
% H_2O	47.57	51.95	49.90
% Ash_d	1.17	2.17	2.42
% S_d	0.02	0.01	0.01
% N_d	0.11	0.08	0.13
HHV_d(Btu/lb)	9,159	9,218	9,907
HHV_d(kJ/kg)	21,300	21,440	23,040

[1]Subscript 'd' designates dry basis.

PLANT AJ1[20]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	1/17/80	1/21/80	1/22/80	
% Isokinetic	50.1	87.9	101.5	
Boiler Load (% of design)	92	90	92	91
Sample Point Location	Inlet of scrubber			
Stack Gas Data				
Flow (Nm^3/s-dry)	23.3	21.5	19.2	21.3
Flow (dscfm)	49,300	45,600	40,700	45,200
Temperature (°C)	193.3	103.9	190.6	162.6
Temperature (°F)	380	219	375	325
Moisture (%)	13.1	18.9	21.0	17.4
Oxygen, dry (%)	14.0	13.9	14.5	14.1
CO_2, dry (%)	9.0	9.3	8.2	8.8
Particulate Emissions				
g/Nm^3-dry	1.098	0.723	1.384	1.068
g/Nm^3-dry @ 12% CO_2	1.464	0.934	1.940	1.446
gr/dscf	0.480	0.316	0.605	0.467
gr/dscf @ 12% CO_2	0.640	0.408	0.848	0.632
ng/J	860.0	559.0	1,170	863
lb/10^6 Btu	2.00	1.30	2.72	2.01
Average Opacity				
Control Device				
Type	MC			
Operating Parameter[1]				
Design Parameter[1]				
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT AJ2[20]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	1/17/80	1/21/80	1/22/80	
% Isokinetic	99.6	95.2	97.1	
Boiler Load (% of design)	92	90	92	91
Sample Point Location	Outlet of scrubber			
Stack Gas Data				
Flow (Nm^3/s-dry)	28.4	26.7	26.8	27.3
Flow (dscfm)	60,200	56,700	56,800	57,900
Temperature (°C)	61.7	60.0	61.1	60.9
Temperature (°F)	143	140	142	142
Moisture (%)	21.3	19.7	20.3	20.4
Oxygen, dry (%)	12.8	14.2	15.0	14.0
CO_2, dry (%)	8.1	7.7	6.5	7.4
Particulate Emissions				
g/Nm^3-dry	0.057	0.60	0.053	0.056
g/Nm^3-dry @ 12% CO_2	0.085	0.092	0.098	0.092
gr/dscf	0.025	0.026	0.023	0.025
gr/dscf @ 12% CO_2	0.037	0.040	0.043	0.040
ng/J	38.3	47.3	48.6	44.7
lb/10^6 Btu	0.089	0.110	0.113	0.104
Average Opacity				
Control Device				
Type	MC/WS			
Operating Parameter[1]				8
Design Parameter[1]				
Design Flow Rate (ACFM)		110,000		

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT AJ3[20]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	1/22/80	1/23/80	1/23/80	
% Isokinetic	101.4	104.9	104.0	
Boiler Load (% of design)	93	95	98	95
Sample Point Location	Inlet of scrubber			
Stack Gas Data				
Flow (Nm^3/s-dry)	20.6	15.3	22.1	19.3
Flow (dscfm)	43,700	32,400	46,900	41,000
Temperature (°C)	189.4	191.7	192.8	191.3
Temperature (°F)	373	377	379	376
Moisture (%)	19.3	20.1	20.1	19.8
Oxygen, dry (%)	15.4	14.5	15.8	15.2
CO_2, dry (%)	9.1	8.9	9.0	9.0
Particulate Emissions				
g/Nm^3-dry	2.391	0.968	1.533	1.631
g/Nm^3-dry @ 12% CO_2	3.153	1.306	2.046	2.169
gr/dscf	1.045	0.423	0.670	0.713
gr/dscf @ 12% CO_2	1.378	0.571	0.894	0.948
ng/J	2,352	817	1,625	1,598
lb/10^6 Btu	5.47	1.90	3.78	3.72
Average Opacity				
Control Device				
Type	MC			
Operating Parameter[1]				
Design Parameter[1]				
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM. For FF, A/C = ft/min.

PLANT AJ4[20]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	1/22/80	1/23/80	1/23/80	
% Isokinetic	100.1	97.3	99.3	
Boiler Load (% of design)	93	94.5	98.2	95
Sample Point Location	Outlet of scrubber			
Stack Gas Data				
Flow (Nm^3/s-dry)	28.4	27.0	25.6	27.0
Flow (dscfm)	60,300	57,200	54,200	57,200
Temperature (°C)	61.7	62.2	63.3	62.4
Temperature (°F)	143	144	146	144
Moisture (%)	21.3	22.6	23.4	22.4
Oxygen, dry (%)	14.6	14.6	15.1	14.9
CO_2, dry (%)	8.2	5.9	6.1	6.7
Particulate Emissions				
g/Nm^3-dry	0.092	0.057	0.053	0.067
g/Nm^3-dry @ 12% CO_2	0.135	0.114	0.104	0.118
gr/dscf	0.040	0.025	0.023	0.0293
gr/dscf @ 12% CO_2	0.059	0.050	0.045	0.051
ng/J	82.6	48.6	49.0	60.1
$lb/10^6$ Btu	0.183	0.113	0.114	0.137
Average Opacity				
Control Device				
Type	MC/WS			
Operating Parameter[1]				13.5
Design Parameter[1]				
Design Flow Rate (ACFM)	110,000			

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM. For FF, A/C = ft/min.

PLANT AJ5 [22]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	7/10/78	7/10/78	7/10/78	
% Isokinetic	93.4	101.2	104.4	
Boiler Load (% of design)	91	91	91	91
Sample Point Location	Outlet of scrubber			
Stack Gas Data				
Flow (Nm^3/s-dry)	23.7	25.5	24.9	24.7
Flow (dscfm)	50,200	54,000	52,800	52,300
Temperature (°C)	65.4	65.4	65.3	65.4
Temperature (°F)	149.7	149.7	149.6	149.7
Moisture (%)	20.2	18.3	20.7	19.7
Oxygen, dry (%)	9.0	8.5	8.8	8.8
CO_2, dry (%)	11.3	12.0	11.8	11.7
Particulate Emissions				
g/Nm^3-dry	0.053	0.057	0.055	0.055
g/Nm^3-dry @ 12% CO_2	0.057	0.057	0.055	0.056
gr/dscf	0.023	0.025	0.024	0.024
gr/dscf @ 12% CO_2	0.025	0.025	0.024	0.024
ng/J	24.5	24.9	24.5	24.6
lb/10^6 Btu	0.057	0.058	0.057	0.057
Average Opacity				
Control Device				
Type	MC/WS			
Operating Parameter[1]				15.2
Design Parameter[1]				
Design Flow Rate (ACFM)	110,000			

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT AK[23,24,25]

Plant AK was tested by the EPA as part of the standards development program. Plant AK has a wood-fired traveling grate spreader stoker rated at 135,000 pounds per hour of steam. The wood fuel consists of 90 percent bark and approximately 10 percent sawdust on the average. Fuel oil is used as a supplementary fuel. Particulate emissions are controlled with a multicyclone followed by a venturi wet scrubber. The normal operating scrubber pressure drop is 20 inches of water. Fly ash collected by the multicyclone passes through a sand classifier and the large particles are reinjected into the boiler furnace.

One test was conducted by the EPA in January, 1980 at both inlet (AK1) and outlet (AK2) of the wet scrubber. During all three test runs the design gas flow rate for the wet scrubber was exceeded. This is believed to be due to the high excess air levels (200, 190, and 320 percent for runs 1, 2, and 3 respectively) measured during the test. During the first two runs the scrubber was still able to effectively control particulate emissions and the scrubber collection efficiency on both runs exceeded 98 percent. During the last run the scrubber particulate inlet loading, excess air, and gas flow rates were higher than the first two runs. Under these conditions the scrubber could no longer effectively control particulate emissions and the scrubber efficiency decreased to 93 percent. Due to the increased inlet loading and reduced scrubber efficiency the emissions at the scrubber outlet were six times higher than outlet emissions for runs 1 and 2.

The increased scrubber inlet particulate loading during test run 3 was most likely due to the measured increase in excess air levels. Though excess air levels may vary due to changing fuel properties, there is no operational requirement for changes in excess air levels of the magnitude shown in test run 3. Also, there is no oxygen analyzer on the boiler. Therefore the boiler operator has no indication of the amount of excess air present in the furnace.

Due to these previously discussed factors, the results of test run 3 are not considered representative of the performance of a venturi wet scrubber operating at a high pressure drop. Therefore this test run is not presented in Chapter 4 and was not used in NSPS development.

Based on test runs 1 and 2 the average emission rate for the January 1980 test was 0.0736 pounds per million Btu. The average boiler load during testing was 94 percent. The scrubber pressure drop monitor was inoperative during testing. However, plant personnel indicated the venturi throat was set for a pressure drop of approximately 20 inches of water.

This plant was later retested by the EPA (AK3) and the particulate emissions at the scrubber outlet averaged 0.0627 pounds per million Btu. The average boiler load was 96 percent of rated capacity during this test. The scrubber pressure drop averaged 26 inches of water. The flue gas flow rates during this test were lower than the previous test, as shown by the lower scrubber outlet flow rates and lower oxygen contents of the flue gas.

For tests AK1, AK2, and AK3, the fuel analyses were as follows:[1]

Test AK1/AK2:	Run 1	Run 2	Run 3
% H_2O	44.9	45.9	43.7
% Ash_d	1.70	1.32	2.17
% S_d	0.04	0.04	0.04
% N_d	0.19	0.17	0.14
HHV_d(Btu/lb)	8,980	9,290	8,980
HHV_d(kJ/kg)	20,880	21,610	20,880

Test AK3	Run 1	Run 2	Run 3
% H_2O	38.3	54.2	42.4
% Ash_d	6.49	2.69	3.55
% S_d	0.110	0.276	0.131
% N_d	0.1	0.1	0.1
HHV_d(Btu/lb)	8,420	9,590	8,520
HHV_d(kJ/kg)	19,580	22,310	19,820

[1] Subscript 'd' designates dry basis.

PLANT AK1[24]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	1/29/80	1/30/80	1/31/80	
% Isokinetic	107.0	101.0	102.5	
Boiler Load (% of design)	81	106	99	95
Sample Point Location	Inlet of scrubber			
Stack Gas Data				
Flow (Nm^3/s-dry)	37.7	34.4	35.9	35.7
Flow (dscfm)	80,000	73,000	76,100	75,700
Temperature (°C)	*	222	216	219
Temperature (°F)	*	431	421	426
Moisture (%)	10.5	14.0	12.9	12.5
Oxygen, dry (%)	14.2	13.8	15.5	14.5
CO_2, dry (%)	5.6	5.8	7.5	6.3
Particulate Emissions				
g/Nm^3-dry	1.89	2.55	3.01	2.48
g/Nm^3-dry @ 12% CO_2	4.06	5.27	4.81	4.71
gr/dscf	0.827	1.113	1.315	1.085
gr/dscf @ 12% CO_2	1.773	2.302	2.104	2.060
ng/J	1,526	1,939	3,014	2,160
lb/10^6 Btu	3.55	4.51	7.01	5.02
Average Opacity				
Control Device				
Type	MC			
Operating Parameter[1]				
Design Parameter[1]				
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

* Thermocouple was broken on this run, stack temperature could not be determined accurately.

PLANT AK2[24]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	*Three	Average
General Data				
Date	1/29/80	1/30/80	11/31/80	
% Isokinetic	98.5	99.6	99.3	
Boiler Load (% of design)	81	106	99	94
Sample Point Location	Outlet of scrubber			
Stack Gas Data				
Flow (Nm^3/s-dry)	33.1	33.1	33.1	33.1
Flow (dscfm)	70,250	70,250	70,250	70,250
Temperature (°C)	55.6	55.6	55.6	55.6
Temperature (°F)	132	132	132	132
Moisture (%)	10.5	14.0	12.9	12.3
Oxygen, dry (%)	14.2	13.8	15.5	14.5
CO_2, dry (%)	5.6	5.8	7.0	5.7
Particulate Emissions				
g/Nm^3-dry	0.034	0.046	0.229	0.040
g/Nm^3-dry @ 12% CO_2	0.076	0.095	0.391	0.086
gr/dscf	0.015	0.020	0.100	0.045
gr/dscf @ 12% CO_2	0.033	0.042	0.171	0.082
ng/J	28.1	35.2	230	31.7
lb/10^6 Btu	0.0653	0.0819	0.5357	0.0736
Average Opacity				
Control Device				
Type	MC/WS			
Operating Parameter[1]				20
Design Parameter[1]				
Design Flow Rate (ACFM)	136,000			

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

*Run 3 is not included in averages.

PLANT AK3 [25]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	6/25/80	6/26/80	6/26/80	
% Isokinetic	103.1	100.5	105.9	
Boiler Load (% of design)	93	106	102	100
Sample Point Location	Outlet of scrubber			
Stack Gas Data				
Flow (Nm^3/s-dry)	28.9	32.3	31.9	31.0
Flow (dscfm)	61,340	68,420	67,610	65,790
Temperature (°C)	60.2	59.9	63.8	61.3
Temperature (°F)	140.3	139.9	146.8	142.3
Moisture (%)	19.2	18.5	21.8	19.8
Oxygen, dry (%)	11.9	11.9	11.6	11.8
CO_2, dry (%)	8.3	8.3	8.0	8.2
Particulate Emissions				
g/Nm^3-dry	0.0739	0.0533	0.0476	0.0583
g/Nm^3-dry @ 12% CO_2	0.1068	0.0764	0.0712	0.0848
gr/dscf	0.0323	0.0233	0.0208	0.0254
gr/dscf @ 12% CO_2	0.0462	0.0334	0.0311	0.0371
ng/J	35.43	22.02	23.48	26.98
lb/10^6 Btu	0.0824	0.0512	0.0546	0.0627
Average Opacity				
Control Device				
Type	MC/WS			
Operating Parameter[1]	25	25.5	27.5	26
Design Parameter[1]				
Design Flow Rate (ACFM)	136,000			

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT AL[26,27,28]

The boiler at Plant AL was tested to determine the particulate emission rate. The boiler is a wood-fired fluidized bed rated at 15,000 pounds of steam per hour fired with bark, sawdust, and shavings. Particulate emissions are controlled by a mechanical collector. Fly ash collected by the mechanical collector is not reinjected.

One EPA Method 5 test consisting of two test runs was performed. The average particulate emission rate was 0.476 pounds per million Btu at an average operating rate of 92 percent of the rated capacity. No steam generation rates were included in the report, so the percent boiler load was based on the mass emission rate and the F-factor.

PLANT AL1[26]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	8/31/77	9/11/77		
% Isokinetic	106.9	107.1		
Boiler Load (% of design)	~92	~92		~92
Sample Point Location	Outlet of MC			
Stack Gas Data				
Flow (Nm^3/s-dry)	3.7	3.6		3.6
Flow (dscfm)	7,787	7,574		7,680
Temperature (°C)	40.3			
Temperature (°F)	104.5			
Moisture (%)	10.63	10.4		10.5
Oxygen, dry (%)	11.6	12.0		11.8
CO_2, dry (%)	8.4	8.1		8.2
Particulate Emissions				
g/Nm^3-dry	0.375	0.332		0.353
g/Nm^3-dry @ 12% CO_2	0.538	0.492		0.515
gr/dscf	0.164	0.145		0.154
gr/dscf @ 12% CO_2	0.235	0.215		0.225
ng/J	212.4	196.5		204.5
lb/10^6 Btu	0.494	0.457		0.476
Average Opacity				
Control Device				
Type	MC			
Operating Parameter[1]				
Design Parameter[1]				
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM. For FF, A/C = ft/min.

PLANT AM[29,30,31]

The boiler at plant AM was tested to determine if it is in compliance with the State of North Carolina emission standards. The waterwall wood-coal combination fuel boiler has a rated steam capacity of 60,000 pounds of steam per hour. Particulates are controlled with one 128 tube mechanical collector. Fly ash collected by the mechanical collector is not reinjected. The boiler's wood fuel consists of kiln dried wood scraps, shavings, and sanderdust. The estimated moisture content of the wood fuel is 6 to 7 percent. The wood scraps are hogged to approximately 1/2 square inch.

One test consisting of three test runs was performed. The average boiler load during testing was 15 percent of rated capacity. The boiler was fired with 100 percent wood during the test. The average particulate emission rate was 0.53 pounds per million Btu.

PLANT AMI[29]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	8/17/79	8/17/79	8/17/79	
% Isokinetic	98.7	106.5	102.9	
Boiler Load (% of design)				15
Sample Point Location	Outlet of MC			
Stack Gas Data				
Flow (Nm^3/s-dry)	6.6	6.6	6.4	6.5
Flow (dscfm)	14,012	13,966	13,489	13,822
Temperature (°C)	153	159	154	155
Temperature (°F)	308	318	309	312
Moisture (%)	3.8	4.0	3.2	3.7
Oxygen, dry (%)	18.0	17.6	18.3	18.0
CO_2, dry (%)	2.7	3.1	2.6	2.8
Particulate Emissions				
g/Nm^3-dry	0.130	0.135	0.114	0.126
g/Nm^3-dry @ 12% CO_2	0.577	0.529	0.529	0.545
gr/dscf	0.057	0.059	0.050	0.055
gr/dscf @ 12% CO_2	0.252	0.231	0.231	0.238
ng/J	232.2	215.0	232.2	226.5
lb/10^6 Btu	0.54	0.50	0.54	0.53
Average Opacity				
Control Device				
Type	MC			
Operating Parameter[1]				
Design Parameter[1]				
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT AN[32]

The boiler at Plant AN was tested to determine the particulate emission rate. The boiler is a wood-fired fluidized bed rated at 36,000 pounds per hour of steam. Particulate emissions are controlled by a mechanical collector. Fly ash collected by the mechanical collector is not reinjected. Approximately 75 percent of the hogged fuel is a mixture of red fir bark, ponderosa pine bark, and white fir bark. The remaining 25 percent of the fuel consists of shavings and sawdust. The average fuel moisture content is 45 percent.

Three EPA Method 5 test runs were performed. The average boiler load was 78 percent of rated capacity during testing. The average particulate emission rate was 0.329 pounds per million Btu.

PLANT AN1[32]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	3/27/79	3/27/79	3/27/79	
% Isokinetic	100.9	101.5	99.9	
Boiler Load (% of design)	73.3	83.3	78.6	78.4
Sample Point Location	Outlet of MC			
Stack Gas Data				
Flow (Nm^3/s-dry)	5.9	6.2	6.3	6.1
Flow (dscfm)	12,630	13,090	13,330	13,020
Temperature (°C)	254	257	260	257
Temperature (°F)	489	495	500	495
Moisture (%)	16.3	16.2	16.2	16.2
Oxygen, dry (%)*	10.3	10.4	10.5	10.4
CO_2, dry (%)	9.7	9.6	9.5	9.5
Particulate Emissions				
g/Nm^3-dry	0.297	0.265	0.281	0.281
g/Nm^3-dry @ 12% CO_2	0.368	0.332	0.355	0.352
gr/dscf	0.13	0.116	0.123	0.123
gr/dscf @ 12% CO_2	0.161	0.145	0.155	0.154
ng/J	147.9	133.3	142.8	141.3
lb/10^6 Btu	0.344	0.310	0.332	0.329
Average Opacity	< 20	< 20	< 20	< 20
Control Device				
Type	MC			
Operating Parameter[1]				
Design Parameter[1]				
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

*O_2 Estimated

PLANT AO[33,34]

The boiler at Plant AO was tested to determine the particulate emission rate. The boiler is a wood-fired fuel cell rated at 25,000 pounds per hour of steam. Particulate emissions are controlled by a mechanical collector. Fly ash collected by the mechanical collector is not reinjected. Bark and hog fuel are used to fire the boiler.

Three EPA Method 5 test runs were made. The average boiler load was 80 percent of rated capacity during testing. The average particulate emission rate was 0.125 pounds per million Btu. During testing, a combination of bark and hog fuel were used to fire the boiler, with the majority of the fuel being bark.

PLANT A01[34]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	7/25/79	7/25/79	7/25/79	
% Isokinetic	103.7	103.2	106.0	
Boiler Load (% of design)	79.6	75.6	86.4	80.5
Sample Point Location	Outlet of MC			
Stack Gas Data				
Flow (Nm^3/s-dry)	3.8	3.5	3.5	3.6
Flow (dscfm)	8,135	7,480	7,445	7,687
Temperature (°C)	163	163	162	163
Temperature (°F)	325	326	323	325
Moisture (%)	17.1	17.1	16.7	17.0
Oxygen, dry (%)	10.6	10.5	10.1	10.5
CO_2, dry (%)	9.8	10.3	10.5	10.2
Particulate Emissions				
g/Nm^3-dry	0.101	0.116	0.096	0.104
g/Nm^3-dry @ 12% CO_2	0.124	0.135	0.110	0.123
gr/dscf	0.044	0.0506	0.0421	0.0456
gr/dscf @ 12% CO_2	0.054	0.059	0.048	0.0537
ng/J	52.85	60.24	48.33	52.81
lb/10^6 Btu	0.123	0.140	0.112	0.125
Average Opacity	3.5	4.5	5	4.3
Control Device				
Type	MC			
Operating Parameter[1]				
Design Parameter[1]				
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT AP[35]

The boiler at Plant AP was tested to determine the particulate emission rate. The boiler is a wood-fired fuel cell rated at 20,000 pounds per hour of steam. Particulate emissions are controlled by a mechanical collector. Fly ash collected by the mechanical collector is not reinjected.

Two EPA Method 5 test runs were made. The average boiler load was 35 percent of rated capacity during testing. The average particulate emission rate was 0.142 pounds per million Btu. The moisture content of the wood fuel was 47 percent. The wood fuel was 95 percent sawdust and 5 percent bark.

PLANT AP1[35]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	7/27/79	7/27/79	___	
% Isokinetic	102.7	97.5	___	
Boiler Load (% of design)	40	30	___	35
Sample Point Location	Outlet of MC			
Stack Gas Data				
Flow (Nm^3/s-dry)	1.7	1.8	___	1.7
Flow (dscfm)	3,549	3,924	___	3,737
Temperature (°C)	117	119	___	118
Temperature (°F)	242	247	___	245
Moisture (%)	18.4	14.0	___	16.2
Oxygen, dry (%)	11.2	10.6	___	10.9
CO_2, dry (%)	9.2	10.2	___	9.7
Particulate Emissions				
g/Nm^3-dry	0.108	0.124	___	0.116
g/Nm^3-dry @ 12% CO_2	0.142	0.144	___	0.143
gr/dscf	0.047	0.054	___	0.051
gr/dscf @ 12% CO_2	0.062	0.063	___	0.062
ng/J	58.5	63.2	___	60.9
$lb/10^6$ Btu	0.136	0.147	___	0.142
Average Opacity	___	___	___	___
Control Device				
Type	MC			
Operating Parameter[1]	___	___	___	___
Design Parameter[1]	___			
Design Flow Rate (ACFM)	___			

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM. For FF, A/C = ft/min.

PLANT AS[36,37]

Plant AS was tested to determine compliance with North Carolina particulate emission standards. This plant has a scotch marine type packaged boiler rated at 5,200 pounds of steam per hour. The boiler fires finely ground wood waste 100 percent in suspension. Particulate emissions are controlled with a mechanical collector. All the fly ash collected by the mechanical collector is reinjected into the boiler furnace.

Three EPA Method 5 test runs were made. The boiler was operated at 60 percent of rated capacity during testing. The average particulate emission rate was 0.759 pounds per million Btu.

PLANT AS1[37]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	8/11/76	8/13/76	8/13/76	
% Isokinetic	97.2	105.0	101.0	
Boiler Load (% of design)	60	60	59	60
Sample Point Location	Outlet of MC			
Stack Gas Data				
Flow (Nm^3/s-dry)	0.745	0.722	0.741	0.736
Flow (dscfm)	1,579	1,528	1,571	1,559
Temperature (°C)	171	171	179	174
Temperature (°F)	339	339	355	344
Moisture (%)	11.0	11.0	11.0	11.0
Oxygen, dry (%)	8.8	8.4	8.8	8.7
CO_2, dry (%)	10.9	12.0	11.6	11.5
Particulate Emissions				
g/Nm^3-dry	0.718	0.750	0.801	0.756
g/Nm^3-dry @ 12% CO_2	0.791	0.750	0.828	0.790
gr/dscf	0.314	0.328	0.350	0.331
gr/dscf @ 12% CO_2	0.346	0.328	0.362	0.545
ng/J	363.4	370.2	408.5	380.7
lb/10^6 Btu	0.728	0.736	0.812	0.759
Average Opacity				
Control Device				
Type	MC			
Operating Parameter[1]				
Design Parameter[1]				
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM. For FF, A/C = ft/min.

PLANT AU[38,39]

The boiler at Plant AU was tested to determine if it is in compliance with the State of North Carolina particulate emission standards. The firetube boiler is fired with wood waste. The boiler is rated at 7,400 pounds of steam per hour. Particulate emissions are controlled with a mechanical collector. Fly ash collected by the mechanical collector is not reinjected.

Three EPA Method 5 test runs were performed. The boiler was operated at an average of 124 percent of rated capacity during testing. The average particulate emission rate was 0.539 pounds per million Btu which is less than the state allowable emission level of 0.56 pounds per million Btu.

PLANT AU1[39]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	3/26/80	3/26/80	3/26/80	
% Isokinetic	106	104	105	
Boiler Load (% of design)	138	124	111	124
Sample Point Location	Outlet of MC			
Stack Gas Data				
Flow (Nm^3/s-dry)	4.1	4.1	4.2	4.1
Flow (dscfm)	8,605	8,693	8,982	8,760
Temperature (°C)	254	256	243	251
Temperature (°F)	489	493	469	484
Moisture (%)	5.9	6.8	5.2	6.0
Oxygen, dry (%)	13.8	14.5	15.5	14.6
CO_2, dry (%)	6.7	6.3	5.1	6.0
Particulate Emissions				
g/Nm^3-dry	0.293	0.270	0.231	0.265
g/Nm^3-dry @ 12% CO_2	0.524	0.515	0.542	0.527
gr/dscf	0.128	0.118	0.101	0.116
gr/dscf @ 12% CO_2	0.229	0.225	0.237	0.230
ng/J	226.2	235.6	233.1	231.6
lb/10^6 Btu	0.526	0.548	0.542	0.539
Average Opacity				
Control Device				
Type	MC			
Operating Parameter[1]				
Design Parameter[1]				
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT AX[40,41]

The boiler at Plant AX was tested to determine if it is in compliance with the State of North Carolina emission standards. The firetube boiler is rated at 2,600 pounds of steam per hour. Particulate emissions are controlled with a mechanical collector. Fly ash collected by the mechanical collector is not reinjected. The boiler is hand fired with wood dust and wood blocks. The boiler also has an auxiliary No.2 fuel oil burner.

Three EPA Method 5 test runs were conducted. The average boiler load was 86 percent of rated capacity during testing. The average particulate emission rate was 0.205 pounds per million Btu which is less than the State allowable emission level of 0.70 pounds per million Btu. Fuel oil provided approximately 19 percent of the heat input during testing.

PLANT AX1[41]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	6/7/77	6/8/77	6/8/77	
% Isokinetic	101.8	101.3	101.3	
Boiler Load (% of design)	87	87	84	86
Sample Point Location	Outlet of MC			
Stack Gas Data				
Flow (Nm^3/s-dry)	1.78	1.74	1.75	1.75
Flow (dscfm)	3,777	3,679	3,707	3,721
Temperature (°C)	184	185	184	184
Temperature (°F)	364	365	363	364
Moisture (%)	3.4	3.6	3.3	3.4
Oxygen, dry (%)	17.8	17.7	17.8	17.8
CO_2, dry (%)	2.5	2.7	2.8	2.7
Particulate Emissions				
g/Nm^3-dry	0.0281	0.0686	0.0613	0.0527
g/Nm^3-dry @ 12% CO_2	0.1357	0.3054	0.2624	0.2345
gr/dscf	0.0123	0.030	0.0268	0.0230
gr/dscf @ 12% CO_2	0.0593	0.1335	0.1147	0.1025
ng/J	47.3	112.4	104.8	88.2
$lb/10^6$ Btu	0.1099	0.2614	0.2438	0.2050
Average Opacity				
Control Device				
Type	MC			
Operating Parameter[1]				
Design Parameter[1]				
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT AY[42,43]

The boiler at plant AY was tested to determine if it is in compliance with the State of North Carolina emission standards. The firetube boiler is rated at 6,040 pounds of steam per hour. Particulate emissions are controlled with a mechanical collector. Fly ash collected by the mechanical collector is not reinjected. The boiler is fueled with wood dust which is dropped into the boiler by means of drop chute. The boiler is also fueled with wood blocks which are hand fed into the boiler.

Three EPA Method 5 test runs were made. The average boiler load was 53 percent of rated capacity during testing. The average particulate emission rate was 0.499 pounds per million Btu which is less than the State allowable emission level of 0.64 pounds per million Btu.

PLANT AY1[43]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	10/5/77	10/5/77	10/5/77	
% Isokinetic	104.0	100.1	100.1	
Boiler Load (% of design)	57	58	45	53
Sample Point Location	Outlet of MC			
Stack Gas Data				
Flow (Nm^3/s-dry)	3.91	3.79	3.90	3.87
Flow (dscfm)	8,287	8,033	8,273	8,198
Temperature (°C)	119	128	120	122
Temperature (°F)	247	262	248	252
Moisture (%)	2.7	3.4	3.0	3.0
Oxygen, dry (%)	18.7	18.5	19.1	18.8
CO_2, dry (%)	2.0	2.5	1.9	2.1
Particulate Emissions				
g/Nm^3-dry	0.082	0.096	0.076	0.085
g/Nm^3-dry @ 12% CO_2	0.494	0.462	0.476	0.477
gr/dscf	0.036	0.042	0.033	0.037
gr/dscf @ 12% CO_2	0.216	0.202	0.208	0.208
ng/J	197.4	218.4	228.1	214.6
lb/10^6 Btu	0.459	0.508	0.530	0.499
Average Opacity				
Control Device				
Type	MC			
Operating Parameter[1]				
Design Parameter[1]				
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT BA[44,45]

Plant BA was tested to determine the efficiency of its electrostatic precipitator (ESP). Plant BA has a wood-fired spreader stoker boiler rated at 110,000 pounds per hour of steam. Bark is the principal fuel supplemented with sanderdust as available. Normal operating load is 70,000 to 75,000 pounds per hour. Particulate emissions are controlled with a mechanical collector followed by an ESP. The ESP has a design SCA of 177 ft^2/1000 ACFM. All of the flyash collected by the mechanical collector is reinjected into the boiler furnace.

Three EPA Method 5 test runs were performed. The average boiler load was 66 percent of capacity during testing. The average particulate emissions were 0.0724 pounds per million Btu. The average SCA during the test was 230 ft^2/1000 ACFM.

PLANT BAI[45]

TEST SUMMARY SHEETS
(Particulates only)

Test Number	One	Two	Three	Average
General Data				
Date	12/18-19/79	12/18-19/79	12/18-19/79	
% Isokinetic	97.5	98.6	93.6	
Boiler Load (% of design)	64	66	67	66
Sample Point Location	Outlet of ESP			
Stack Gas Data				
Flow (Nm^3/s-dry)	19.2	19.4	19.3	19.8
Flow (dscfm)	40,630	41,110	41,050	41,930
Temperature (°C)	182	182	184	183
Temperature (°F)	360	359	364	361
Moisture (%)	12.3	15.2	11.9	13.1
Oxygen, dry (%)	10.0	9.8	8.4	9.4
CO_2, dry (%)	9.3	9.0	9.4	9.2
Particulate Emissions				
g/Nm^3-dry	0.039	0.062	0.101	0.067
g/Nm^3-dry @ 12% CO_2	0.050	0.082	0.128	0.087
gr/dscf	0.017	0.027	0.044	0.029
gr/dscf @ 12% CO_2	0.022	0.036	0.056	0.038
ng/J	19.7	30.5	43.0	31.1
lb/10^6 Btu	0.0459	0.0710	0.100	0.0724
Average Opacity				
Control Device				
Type	MC/ESP			
Operating Parameter[1]	235	224	230	230
Design Parameter[1]	177			
Design Flow Rate (ACFM)	93,490			

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT BB[46,47]

Plant BB was tested to determine compliance with State emission standards. Plant BB has a wood-fired spreader stoker boiler rated at 450,000 pounds per hour of steam. Particulate emissions are controlled by a Zurn multiclone followed by an ESP. The ESP has a design collection area of 95,806 ft^2 and is sized for a gas flow up to 322,000 ACFM. The fly ash collected by the multiclone passes through a sand classifier and the large fraction is reinjected into the boiler furnace.

Three EPA Method 5 test runs were performed. The average boiler load during testing was 69 percent of rated capacity, and the average SCA for the ESP was 453 ft^2/100 ACFM based on an operating collection area of 87,696 ft^2. Natural gas provided an average of 1.8 percent of the heat input during testing. The average particulate emission rate was 0.0571 pounds per million Btu.

No fuel sampling was done during testing, however, a typical analysis of the wood fuel is as follows:[1]

% H_2O	- 42.5
% Ash_d	- 4.8
HHV_d(Btu/lb)	- 8250
HHV_d(kJ/kg)	- 19,190

[1]Subscript 'd' denotes dry basis.

PLANT BB[47]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	6/10/80	6/11/80	6/12/80	
% Isokinetic	102	106	104	
Boiler Load (% of design)	74	68	66	69
Sample Point Location	Outlet of ESP			
Stack Gas Data				
Flow (Nm^3/s-dry)	45.2	52.5	48.4	48.7
Flow (dscfm)	95,696	111,307	102,439	103,147
Temperature (°C)	164	162	154	160
Temperature (°F)	327	323	310	320
Moisture (%)	22.1	20.0	21.2	21.1
Oxygen, dry (%)	4.8	7.1	7.0	6.3
CO_2, dry (%)	15.5	13.2	12.9	13.9
Particulate Emissions				
g/Nm^3-dry	0.0519	0.0817	0.0668	0.0668
g/Nm^3-dry @ 12% CO_2	0.0403	0.0744	0.0622	0.0577
gr/dscf	0.0227	0.0357	0.0292	0.0292
gr/dscf @ 12% CO_2	0.0176	0.0325	0.0272	0.0252
ng/J	17.0	31.2	25.4	24.6
lb/10^6 Btu	0.0396	0.0726	0.0591	0.0571
Average Opacity				
Control Device				
Type	MC/ESP			
Operating Parameter[1]	475	424	461	453
Design Parameter[1]	298			
Design Flow Rate (ACFM)	322,000			

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT BC[48,49]

Plant BC was tested by the EPA as part of the standards development program. Plant BC has three dutch oven type wood-fired boilers. Each boiler was originally rated at 55,000 pounds per hour of steam. However, due to their age (over 40 years), their maximum steam capacity is now approximately 50,000 pounds per hour. The boilers are fired with wood waste and bark from Canadian limber mills, local sawmills, and the plant's debarking operations. Approximately 80 percent of the fuel comes from logs stored in salt water.

Each boiler has an individual mechanical collector. After exiting the mechanical collector, the flue gases are combined into a single duct and enter a baghouse. Fly ash collected by the mechanical collectors is not reinjected.

A particulate emission test was conducted simultaneously at the inlet (BC1) and outlet (BC2) of the baghouse. The boilers were operated at an average of 91 percent of capacity during testing. The average A/C for the fabric filter during testing was 2.98 ft/min. The average particulate emission rate was 0.020 pounds per million Btu at the fabric filter outlet.

The average analysis of fuel samples collected during testing is as follows.[1]

% H_2O	- 56.7
% Ash_d	- 3.4
% S_d	- 0.1
% N_d	- 0.2
% $Chlorides_d$	- 0.4
HHV_d (Btu/lb)	- 8,619
HHV_d (kJ/kg)	- 20,050

[1] Subscript 'd' denotes dry basis.

PLANT BC1[49]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	11/19/80	11/20/80	11/22/80	
% Isokinetic	99.6	104.7	107.2	
Boiler Load (% of design)	89	86	99	91
Sample Point Location	Inlet to Fabric Filter			
Stack Gas Data				
Flow (Nm^3/s-dry)	35.8	36.4	33.8	35.4
Flow (dscfm)	75,917	77,217	71,610	74,915
Temperature (°C)	207	201	209	205.7
Temperature (°F)	405	393	409	402
Moisture (%)	17.4	17.0	23.6	19.3
Oxygen, dry (%)	12.4	11.7	9.4	11.2
CO_2, dry (%)	7.6	8.4	10.8	8.9
Particulate Emissions				
g/Nm^3-dry	1.05	0.993	1.36	1.13
g/Nm^3-dry @ 12% CO_2	1.65	1.41	1.51	1.52
gr/dscf	0.458	0.434	0.594	0.495
gr/dscf @ 12% CO_2	0.723	0.620	0.660	0.668
ng/J	650	576	623	615
lb/10^6 Btu	1.51	1.34	1.44	1.43
Average Opacity				
Control Device				
Type	MC			
Operating Parameter[1]				
Design Parameter[1]				
Design Flow Rate (ACFM)	180,000			

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT BC2[49]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	11/19/80	11/20/80	11/22/80	
% Isokinetic	100.6	99.7	108.2	
Boiler Load (% of design)	89	86	99	91
Sample Point Location	Outlet of Fabric Filter			
Stack Gas Data				
Flow (Nm^3/s-dry)	39.5	39.6	37.0	38.7
Flow (dscfm)	83,653	83,855	78,312	81,940
Temperature (°C)	159	161	162	161
Temperature (°F)	318	322	323	321
Moisture (%)	16.7	16.5	22.4	18.5
Oxygen, dry (%)	9.2	12.3	10.6	10.7
CO_2, dry (%)	10.8	7.8	9.6	9.4
Particulate Emissions				
g/Nm^3-dry	0.0267	0.0128	0.0119	0.0171
g/Nm^3-dry @ 12% CO_2	0.0297	0.0197	0.0149	0.0214
gr/dscf	0.0117	0.0056	0.0052	0.0075
gr/dscf @ 12% CO_2	0.013	0.0086	0.0065	0.0094
ng/J	12.1	7.86	6.09	8.68
lb/10^6 Btu	0.0281	0.0183	0.0142	0.0202
Average Opacity	9.2	2.2	0.1	4.3
Control Device				
Type	MC/FF			
Operating Parameter[1]	2.97	2.98	3.00	2.98
Design Parameter[1]	3.64			
Design Flow Rate (ACFM)	180,000			

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT BD[50,51]

Plant BD was tested by the EPA as part of the standards development program. Plant BD has a wood-fired spreader stoker boiler rated at 25,000 pounds steam per hour. The wood fuel consists of hogged bark.

The flue gas from the boiler passes through a knockout box, a cyclone, a second knockout box, and finally a fabric filter with a design air-to-cloth ratio of 4.1 ft/min. The knockout boxes are used to collect large carbon particles which can cause fires in the baghouse. Fly ash collected by the cyclone is not reinjected.

Particulate testing was performed prior to the second knockout box (BD1) and after the fabric filter (BD2). The boiler was estimated to operate at 75 percent of rated capacity during emission testing. There is no steam flow meter on the boiler, so operating rate was estimated by using heat input calculated using the F-factor and the heat input required to produce steam at rated capacity. The average air-to-cloth ratio for the fabric filter during testing was 3.66 feet per minute. The average emission rate was 0.016 pounds per million Btu at the fabric filter outlet.

Fuel samples collected during testing showed the following average composition:[1]

% H_2O	- 46.6
% Ash_d	- 5.1
% S_d	- 0.06
% N_d	- 0.6
HHV_d (Btu/lb)	- 8325
HHV_d (kJ/kg)	- 19,364

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[1]Subscript 'd' denotes dry basis.

PLANT BD1[51]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	12/16/80	12/17/80	12/18/80	
% Isokinetic	99.2	104.3	101.6	
Boiler Load (% of design)	76	73	77	75
Sample Point Location	Inlet to Fabric Filter			
Stack Gas Data				
Flow (Nm^3/s-dry)	4.04	3.82	3.83	3.90
Flow (dscfm)	8563	8091	8121	8259
Temperature (°C)	191	199	200	197
Temperature (°F)	375	390	392	386
Moisture (%)	14.5	16.8	18.9	16.7
Oxygen, dry (%)	10.0	10.7 [2]	10.0	10.2
CO_2, dry (%)	9.3	8.9 [2]	9.1	9.1
Particulate Emissions				
g/Nm^3-dry	0.796	0.856	0.899	0.850
g/Nm^3-dry @ 12% CO_2	1.03	1.15	1.19	1.12
gr/dscf	0.348	0.374	0.393	0.372
gr/dscf @ 12% CO_2	0.449	0.504	0.518	0.490
ng/J	395	452	446	431
$lb/10^6$ Btu	0.919	1.06	1.04	1.01
Average Opacity				
Control Device				
Type	MC			
Operating Parameter[1]				
Design Parameter[1]				
Design Flow Rate (ACFM)	24,600			

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM. For FF, A/C = ft/min.

[2]These values are for the gas analysis of the fabric filter outlet for run 2. The values obtained during testing were considered to be inaccurate.

PLANT BD2[51]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	12/16/80	12/17/80	12/18/80	
% Isokinetic	96.7	96.8	104.2	
Boiler Load (% of design)	76	73	77	75
Sample Point Location	Outlet of Fabric Filter			
Stack Gas Data				
Flow (Nm^3/s-dry)	4.26	4.36	3.97	4.20
Flow (dscfm)	9026	9232	8414	8891
Temperature (°C)	121	124	126	124
Temperature (°F)	250	255	259	255
Moisture (%)	13.2	16.2	19.6	16.3
Oxygen, dry (%)	10.0	10.7	9.0	9.9
CO_2, dry (%)	9.3	8.9	11.1	9.8
Particulate Emissions				
g/Nm^3-dry	0.0121	0.0144	0.0158	0.0142
g/Nm^3-dry @ 12% CO_2	0.0156	0.0194	0.0172	0.0174
gr/dscf	0.0053	0.0063	0.0069	0.0062
gr/dscf @ 12% CO_2	0.0068	0.0085	0.0075	0.0076
ng/J	6.02	7.64	7.18	6.95
lb/10^6 Btu	0.0140	0.0178	0.0167	0.0162
Average Opacity	———	———	———	———
Control Device				
Type	MC/FF			
Operating Parameter[1]	3.53	3.81	3.64	3.66
Design Parameter[1]	4.1			
Design Flow Rate (ACFM)	24,600			

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT BE[52,53]

Plant BE was tested by the EPA as part of the standards development program. Plant BE has a wood-fired spreader stoker boiler rated at 400,000 pounds per hour steam when firing hog fuel with a 55 percent moisture content. Particulate emissions are controlled by two multiclones and a electrostatic granular filter (EGB) with three modules.

The flyash collected by the first multiclone is slurried and passed over screens. The larger particles are then mixed with the hog fuel. The fuel samples were taken after the flyash had been mixed with the hog fuel.

The flue gas from the boiler passes through the two multiclones in series and is then split into three ducts. Each duct enters one module of the EGB and each module has a separate stack. Particulate emissions were measured at the inlet of module three and on all three stacks simultaneously. The emission data presented as test BE1 is the data collected on the inlet to module 3. The emission data presented as test BE2 is the weighted average of all three stacks, except for the gas flow which is the sum of the three stacks.

The average boiler load during testing was 96 percent of capacity and the pressure drop across the EGB averaged 6 inches of water. The average emission rate was 0.0275 $lb/10^6$ Btu at the EGB outlet.

The analyses of the fuel samples taken during testing were as follows:

	Run 1	Run 2	Run 3
% H_2O	54.9	57.1	55.9
% Ash_d	4.8	8.4	12.8
% S_d	0.06	0.06	0.08
% N_d	0.14	0.16	0.12
HHV_d (Btu/lb)	8224	8541	8039
HHV_d (kJ/kg)	19129	19866	18699

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[a]Subscript 'd' denotes dry basis.

Plant BE was also tested by the company to determine the performance of the EGB over a variety of operating conditions. The data presented were collected at the outlet of module 3 of the EGB. The test consisted of 15 test runs. During one test run, number 6, the electrostatic grid was turned off. This test run would not be representative of normal operation and is not presented. The remaining data were separated into four groups:

Test BE3 - test runs made with "good" fuel and fly ash reinjection

Test BE4 - test runs made with "good" fuel without fly ash reinjection

Test BE5 - test runs made with "poor" fuel and fly ash reinjection

Test BE6 - test runs made with "poor" fuel without fly ash reinjection

"Good" fuel was defined as fuel with a moisture content of less than 55 percent (wet basis). "Poor" fuel had a moisture content over 55 percent.

During runs 8, 11, 12, and 14 the inlet loading to the EGB exceeded design specifications. Though outlet emissions were low, there is a possibility that the EGB could not continuously control PM emissions to the levels shown if the inlet loading remained above the design limit.

The pressure drop across module 3 ranged from 1.2 to 7.9 inches of water during testing. The emission rate ranged from 0.017 to 0.068 lb/10^6 Btu. The boiler operating rate varied from 62 to 140 percent of rated capacity.

The average analyses of the fuel samples collected during testing were as follows:

	Test BE3	Test BE4	Test BE5	Test BE6
% H_2O	48.6	49.8	58.2	59.0
% Ash_d	3.84	3.82	4.80	4.85
% N_d	0.12	0.18	0.13	0.15
HHV_d (Btu/lb)	8,970	8,910	8,780	8,830
HHV_d (kJ/kg)	20,860	20,725	20,430	20,550

Subscript 'd' denotes dry basis.

PLANT BE1[52]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	12/9/80	12/10/80	12/11/81	
% Isokinetic	89.7	102.7	150	
Boiler Load (% of design)	100	101	87	96
Sample Point Location	Inlet to Module 3 of electroscrubber			
Stack Gas Data				
Flow (Nm^3/s-dry)	33.9	32.6	29.2	31.9
Flow (dscfm)	71,810	69,078	61,822	67,570
Temperature (°C)	168	172	168	169
Temperature (°F)	334	342	335	337
Moisture (%)	19.7	26.1	22.4	22.7
Oxygen, dry (%)	10.6	9.8	9.8	10.1
CO_2, dry (%)	7.8	8.3	10.2	8.8
Particulate Emissions				
g/Nm^3-dry	0.362	0.604	0.428	0.465
g/Nm^3-dry @ 12% CO_2	0.556	0.874	0.503	0.644
gr/dscf	0.158	0.264	0.187	0.203
gr/dscf @ 12% CO_2	0.243	0.382	0.220	0.282
ng/J	185	287	204	225
lb/10^6 Btu	0.430	0.668	0.473	0.524
Average Opacity				
Control Device				
Type	2 x MC			
Operating Parameter[1]				
Design Parameter[1]				
Design Flow Rate (ACFM)	420,000			

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT BE2[52]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	12/9/80	12/10/80	12/11/80	
% Isokinetic	98.9	105	98.6	
Boiler Load (% of design)	100	101	87	96
Sample Point Location	Outlet of EGB			
Stack Gas Data				
Flow (Nm^3/s-dry)	83.5	89.6	79.0	84.0
Flow (dscfm)	176,939	189,870	167,401	178,070
Temperature (°C)	156	161	158	158
Temperature (°F)	313	322	317	317
Moisture (%)	21.2	23.2	21.3	21.9
Oxygen, dry (%)	9.7	9.1	10.0	9.6
CO_2, dry (%)	10.3	10.9	10.1	10.4
Particulate Emissions				
g/Nm^3-dry	0.0229	0.0272	0.0259	0.0253
g/Nm^3-dry @ 12% CO_2	0.0268	0.0300	0.0307	0.0292
gr/dscf	0.0100	0.0119	0.0113	0.0111
gr/dscf @ 12% CO_2	0.0117	0.0131	0.0134	0.0127
ng/J	10.8	12.1	12.5	11.8
lb/10^6 Btu	0.0251	0.0283	0.0291	0.0275
Average Opacity				
Control Device				
Type	2 x MC/EGB			
Operating Parameter[1]	5.5	6.6	5.8	6.0
Design Parameter[1]				
Design Flow Rate (ACFM)	420,000			

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min. For EGB, pressure drop = "H_2O.

PLANT BE3[53]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
	1	2	5	
General Data				
Date	9/22/80	9/23/80	9/24/80	
% Isokinetic	110	107	82	
Boiler Load (% of design)	102	108	62	___
Sample Point Location	Outlet of EGB Module 3			
Stack Gas Data				
Flow (Nm^3/s-dry)	25.7	27.4	19.4	___
Flow (dscfm)	54,449	58,051	41,101	___
Temperature (°C)	172	168	158	___
Temperature (°F)	342	334	316	___
Moisture (%)	22.4	21.7	16.0	___
Oxygen, dry (%)	7.3	7.1	9.7	___
CO_2, dry (%)	13.6	13.1	10.5	___
Particulate Emissions				
g/Nm^3-dry	0.022	0.031	0.032	___
g/Nm^3-dry @ 12% CO_2	0.019	0.028	0.036	___
gr/dscf	0.010	0.014	0.014	___
gr/dscf @ 12% CO_2	0.008	0.012	0.016	___
ng/J	8.53	11.8	15.1	___
$lb/10^6$ Btu	0.020	0.027	0.035	___
Average Opacity	___	___	___	___
Control Device				
Type	2xMC/EGB			
Operating Parameter[1]	2.9	3.3	1.2	___
Design Parameter[1]	___			
Design Flow Rate (ACFM)	140,000			

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min. For EGB, pressure drop="H_2O

PLANT BE3[53]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
	7	9		
General Data				
Date	9/26/80	9/29/80	____	
% Isokinetic	99	101	____	
Boiler Load (% of design)	116	118	____	101
Sample Point Location	Outlet of EGB Module 3			
Stack Gas Data				
Flow (Nm^3/s-dry)	29.8	30.8	____	26.6
Flow (dscfm)	63,136	65,254	____	56,356
Temperature (°C)	173	177	____	170
Temperature (°F)	343	351	____	338
Moisture (%)	24.0	22.6	____	21.3
Oxygen, dry (%)	6.7	8.5	____	7.9
CO_2, dry (%)	13.3	11.8	____	12.5
Particulate Emissions				
g/Nm^3-dry	0.026	0.021	____	0.026
g/Nm^3-dry @ 12% CO_2	0.024	0.021	____	0.026
gr/dscf	0.011	0.009	____	0.011
gr/dscf @ 12% CO_2	0.010	0.009	____	0.011
ng/J	9.66	8.93	____	10.8
lb/10^6 Btu	0.022	0.021	____	0.025
Average Opacity	____	____	____	____
Control Device				
Type	2xMC/EGB			
Operating Parameter[1]	off	6.6	____	3.4
Design Parameter[1]	____			
Design Flow Rate (ACFM)	140,000			

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM. For FF, A/C = ft/min. For EGB, Pressure drop="H_2O

PLANT BE4[53]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
	3	4	8	
General Data				
Date	9/23/80	9/24/80	9/26/80	
% Isokinetic	92.7	96	102	
Boiler Load (% of design)	108	100	140	___
Sample Point Location	Outlet of EGB Module 3			
Stack Gas Data				
Flow (Nm^3/s-dry)	26.9	23.8	34.5	___
Flow (dscfm)	56,992	50,424	73,093	___
Temperature (°C)	168	159	186	___
Temperature (°F)	334	318	367	___
Moisture (%)	19.4	20.7	23.8	___
Oxygen, dry (%)	7.7	6.8	7.0	___
CO_2, dry (%)	12.6	12.9	13.8	___
Particulate Emissions				
g/Nm^3-dry	0.034	0.020	0.033	___
g/Nm^3-dry @ 12% CO_2	0.032	0.018	0.028	___
gr/dscf	0.015	0.009	0.014	___
gr/dscf @ 12% CO_2	0.014	0.008	0.012	___
ng/J	13.6	7.48	12.5	___
lb/10^6 Btu	0.032	0.017	0.029	___
Average Opacity	___	___	___	___
Control Device				
Type	2xMC/EGB			
Operating Parameter[1]	2.9	2.1	7.0	___
Design Parameter[1]	___			
Design Flow Rate (ACFM)	140,000			

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min. For EGB, pressure drop="H_2O

PLANT BE4[53]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
	15			
General Data				
Date	10/3/80			
% Isokinetic	100			
Boiler Load (% of design)	118			116
Sample Point Location	Outlet of EGB Module 3			
Stack Gas Data				
Flow (Nm^3/s-dry)	30.7			29.0
Flow (dscfm)	65,042			61,441
Temperature (°C)	169			170
Temperature (°F)	336			338
Moisture (%)	21.8			21.4
Oxygen, dry (%)	7.5			7.2
CO_2, dry (%)	12.4			12.9
Particulate Emissions				
g/Nm^3-dry	0.020			0.027
g/Nm^3-dry @ 12% CO_2	0.019			0.024
gr/dscf	0.009			0.012
gr/dscf @ 12% CO_2	0.008			0.010
ng/J	7.87			10.4
lb/10^6 Btu	0.018			0.024
Average Opacity				
Control Device				
Type	2xMC/EGB			
Operating Parameter[1]	4.1			4.0
Design Parameter[1]				
Design Flow Rate (ACFM)	140,000			

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min. For EGB, pressure drop="H_2O

PLANT BE5[53]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
	10	11	13	
General Data				
Date	9/30/80	10/1/80	10/2/80	
% Isokinetic	91.8	102	102	
Boiler Load (% of design)	102	102	81	95
Sample Point Location	Outlet of EGB Module 3			
Stack Gas Data				
Flow (Nm^3/s-dry)	31.2	31.0	24.0	28.7
Flow (dscfm)	66,102	65,678	50,847	60,805
Temperature (°C)	187	183	174	181
Temperature (°F)	369	361	345	358
Moisture (%)	24.7	25.5	25.1	25.1
Oxygen, dry (%)	8.5	8.0	7.8	8.1
CO_2, dry (%)	11.8	11.3	12.2	11.8
Particulate Emissions				
g/Nm^3-dry	0.037	0.049	0.035	0.040
g/Nm^3-dry @ 12% CO_2	0.037	0.052	0.035	0.041
gr/dscf	0.016	0.021	0.015	0.018
gr/dscf @ 12% CO_2	0.016	0.023	0.015	0.018
ng/J	15.7	20.0	14.1	16.6
lb/10^6 Btu	0.037	0.047	0.033	0.039
Average Opacity				
Control Device				
Type	2xMC/EGB			
Operating Parameter[1]	7.9	5.9	2.9	5.6
Design Parameter[1]				
Design Flow Rate (ACFM)	140,000			

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min. For EGB, pressure drop = "H_2O

PLANT BE6[53]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
	12	14		
General Data				
Date	10/1/80	10/2/80	____	
% Isokinetic	98.7	____	____	
Boiler Load (% of design)	102	112	____	107
Sample Point Location	Outlet of EGB Module 3		____	
Stack Gas Data				
Flow (Nm^3/s-dry)	34.8	34.0	____	34.4
Flow (dscfm)	73,729	72,034	____	72,881
Temperature (°C)	189	196	____	192
Temperature (°F)	372	385	____	378
Moisture (%)	23.3	24.9	____	24.1
Oxygen, dry (%)	9.2	8.2	____	8.7
CO_2, dry (%)	11.2	12.0	____	11.6
Particulate Emissions				
g/Nm^3-dry	0.065	0.035	____	0.050
g/Nm^3-dry @ 12% CO_2	0.069	0.035	____	0.052
gr/dscf	0.028	0.015	____	0.022
gr/dscf @ 12% CO_2	0.030	0.015	____	0.023
ng/J	29.3	14.5	____	21.9
lb/10^6 Btu	0.068	0.034	____	0.051
Average Opacity	____	____	____	____
Control Device				
Type	2xMC/EGB			
Operating Parameter[1]	7.1	7.1	____	7.1
Design Parameter[1]	____			
Design Flow Rate (ACFM)	____			

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM. For FF, A/C = ft/min. For EGB, pressure drop-"H_2O

PLANT BF[54,55,56]

Plant BF was tested to determine the particulate emission rate. Plant BF has a tangentially fired boiler rated at 350,000 pounds per hour of steam. The fuel is 75 percent coal and 25 percent wood on a heat input basis. Particulate emissions are controlled by a 290 tube mechanical collector followed by two venturi wet scrubbers in parallel. The wet scrubbers vent through a common stack. The normal operating scrubber pressure drop is 9 inches of water. Fly ash collected by the mechanical collector is not reinjected.

This boiler is an unusual design. In this boiler there are no grates so the bark and sawdust are fired in suspension with the coal. The original purpose of having wood firing capabilities in this boiler was to dispense of wood waste rather than to recover energy from the wood. According to plant personnel, no new boilers of this type are expected.

This boiler design would not be typical of boilers firing wood in suspension. Typical suspension wood-fired boilers fire dry fine fuels such as sanderdust.

Three EPA Method 5 test runs were performed. Emissions were measured at the inlet (BF1) and outlet (BF2) of the wet scrubbers so that their efficiency could be calculated. The average boiler load during testing was 94 percent of rated capacity. The average emissions were 0.028 pounds per million Btu. The average collector efficiency was 99.7 percent. The scrubber pressure drop during the tests was normal.

PLANT BF1 [54,56]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	5/5/77	5/5/77	5/5/77	
% Isokinetic	100.1	102.4	104.1	
Boiler Load (% of design)	96.0	93.1	95.2	94
Sample Point Location	Inlet of Scrubber			
Stack Gas Data				
Flow (Nm^3/s-dry)	60.3	55.0	55.4	56.9
Flow (dscfm)	127,800	116,700	117,500	120,700
Temperature (°C)	196	226	226	216
Temperature (°F)	385	439	438	421
Moisture (%)	12.7	7.7	11.2	10.5
Oxygen, dry (%)	9.0	9.0	9.0	9.0
CO_2, dry (%)	10.8	10.8	10.8	10.8
Particulate Emissions				
g/Nm^3-dry	9.86	9.43	8.88	9.39
g/Nm^3-dry @ 12% CO_2	10.96	10.48	9.86	10.43
gr/dscf	4.31	4.12	3.88	4.10
gr/dscf @ 12% CO_2	4.79	4.58	4.31	4.56
ng/J	4,532	4,334	4,081	4,317
lb/10^6 Btu	10.54	10.08	9.49	10.04
Average Opacity				
Control Device				
Type	MC			
Operating Parameter[1]				
Design Parameter[1]				
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT BF2[54,56]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	5/5/77	5/5/77	5/5/77	
% Isokinetic	96.0	93.1	95.2	
Boiler Load (% of design)	___	___	___	94
Sample Point Location	Outlet of Scrubber			
Stack Gas Data				
Flow (Nm^3/s-dry)	71.1	70.7	70.8	70.8
Flow (dscfm)	150,700	149,800	150,200	150,200
Temperature (°C)	62.2	63.9	63.3	63.1
Temperature (°F)	144	147	146	146
Moisture (%)	12.7	7.7	112	10.5
Oxygen, dry (%)	9.0	9.0	9.0	9.0
CO_2, dry (%)	10.8	10.8	10.8	10.8
Particulate Emissions				
g/Nm^3-dry	0.025	0.028	0.025	0.026
g/Nm^3-dry @ 12% CO_2	0.028	0.030	0.028	0.029
gr/dscf	0.011	0.012	0.011	0.011
gr/dscf @ 12% CO_2	0.012	0.013	0.012	0.012
ng/J	11.6	12.5	11.6	11.9
lb/10^6 Btu	0.027	0.029	0.027	0.028
Average Opacity	___	___	___	___
Control Device				
Type	MC/WS			
Operating Parameter[1]	___	___	___	9
Design Parameter[1]	8-10			
Design Flow Rate (ACFM)	___			

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT BG[57,58]

An emission test was performed at plant BG to determine compliance with the State of Washington emission standards. The boiler fires hog fuel and oil. Sludge can also be burned. The boiler is rated at 200,000 pounds per hour of steam. Particulates are controlled with a 600 tube multicyclone and a venturi wet scrubber. The design scrubber pressure drop is 15 to 20 inches of water. Fly ash collected by the mechanical collector is not reinjected.

Three test runs were made in accordance with EPA Method 5. During testing the boiler load was steady at 75 percent of rated capacity and 10 percent of the heat input was from No. 6 fuel oil. The wet scrubber had a pressure drop of 19 inches of water during testing. The average emissions were 0.15 pounds per million Btu which is below the State allowable emissions of 0.216 pounds per million Btu. The fuel contained approximately 0.4 percent salt (dry basis) and the particulate measured at the outlet of the scrubber contained 13.3 percent salt.

PLANT BG1

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	2/8/78	2/8/78	2/8/78	
% Isokinetic	99	99.7	92.4	
Boiler Load (% of design)	75	75	75	75
Sample Point Location	Outlet of scrubber			
Stack Gas Data				
Flow (Nm^3/s-dry)	22.7	22.1	22.5	22.4
Flow (dscfm)	48,100	46,900	47,600	47,500
Temperature (°C)	66.7	68.3	66.1	67.0
Temperature (°F)	152	155	151	153
Moisture (%)	27.4	28.9	26.2	27.5
Oxygen, dry (%)	6.5	6.9	7.0	6.8
CO_2, dry (%)	13.2	12.9	13.0	13.0
Particulate Emissions				
g/Nm^3-dry	0.174	0.174	0.167	0.172
g/Nm^3-dry @ 12% CO_2	0.158	0.162	0.156	0.158
gr/dscf	0.076	0.076	0.073	0.075
gr/dscf @ 12% CO_2	0.069	0.071	0.068	0.069
ng/J	64.1	65.4	63.6	64.4
lb/10^6 Btu	0.149	0.152	0.148	0.150
Average Opacity				
Control Device				
Type	MC/WS			
Operating Parameter[1]				19
Design Parameter[1]	8-10			
Design Flow Rate (ACFM)	174,000			

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT BH[59,60,61,62,63]

Boilers No. 4 and 5 were tested to determine the efficiency of their ESPs and to obtain particulate emission rate data for the development of New Source Performance Standards. Boiler No. 4 is a pulverized coal unit rated at 140,000 pounds per hour of steam. Boiler No. 5 is a wood-fired spreader stoker rated at 200,000 pounds per hour of steam. The flue gases from each boiler pass through individual mechanical collectors. The flue gases are then combined into a single duct and then split and sent to identical ESPs. Each ESP has a separate stack. The design SCA for each ESP is 460 ft^2/1000 ACFM. All of the fly ash collected by the mechanical collector on boiler No.5 is reinjected into the No.5 boiler furnace.

Three EPA Method 5 tests were run; two were performed by the EPA. The first EPA test was performed at the inlet of each cyclone (BH7, BH8) and the outlet of both ESPs (BH9) on December 12-14, 1979. This test showed emission rates at the ESP outlets (0.454 pounds per million Btu) that were 10 times higher than previous industry tests. Opacity readings taken during testing also indicated much higher emission rates than would be expected for an ESP. Discussions with plant personnel and the ESP vendor indicated that emissions this high were in no way normal for this facility. A possible explanation is that the ash in the ESP hoppers had "bridged over" and was being re-entrained in the flue gas. This problem had occurred at this facility before but is not considered part of normal operation. This facility was retested on September 23, 1980 and the results were similar to the industry data. This tended to confirm that the results of the December 12-14, 1979 test were not indicative of normal operation. Therefore, the Method 5 and opacity results of the first test were not used in NSPS development.

The industry test had average particulate emissions of 0.008 pounds per million Btu. The test was conducted at the inlets (BH1) and outlets (BH2) of the ESPs. Boiler No.4 was operated at 84 percent of rated capacity and Boiler No.5 was operated at 46 percent of rated capacity. Wood fuel provided an average of 80 percent of the total heat input to boiler No.5 during this test. The average SCA during this test based on the combined air flow of each ESP unit was 600 ft^2/1000 ACFM.

The second EPA test, conducted on September, 1980 showed an average emission rate from each ESP of 0.0675 pounds per million Btu. The test was conducted at the inlet of both mechanical collectors (BH3, BH4), and the outlets of the ESPs (BH6). Boiler No. 4 was operated at 48 percent of rated capacity and boiler No.5 was operated at 88 percent of rated capacity. Wood fuel provided over 99 percent of the heat input for boiler No.5 during testing. The average SCA during testing based on the combined air flow of each ESP unit was 452 ft^2/1000 ACFM.

The test data presented for the inlet and outlet of the ESPs is the weighted average of both ESPs, except for the gas flow rate which is the sum of both ESPs.

For test BH1/BH2, the fuel analyses were as follows:[1]

Test BH1/BH2	Run 1 coal/bark	Run 2 coal/bark	Run 3 coal/bark
% H_2O	2.88/31.66	2.55/32.43	4.03/21.20
% Ash_d	12.89/6.89	23.98/6.21	16.26/4.55
% S_d	0.47/0.25	0.80/0.11	0.41/0.18
% N_d	1.37/0.02	0.89/0.03	0.94/0.02
HHV_d(Btu/lb)	13,080/8,370	11,320/8,210	12,590/7,880
HHV_d(kJ/kg)	30,420/19,460	26,320/19,100	29,280/18,330

For test BH3/BH4/BH6 fuel analyses were as follows:[1]

Tests BH3/BH4/BH6	Run 1 coal/bark	Run 2 coal/bark	Run 3 coal/bark
% H_2O	3.15/43.1	3.91/43.9	4.54/39.5
% Ash_d	6.38/4.83	7.79/4.59	7.14/3.85
% S_d	0.58/0.02	0.94/0.03	0.60/0.04
% N_d	1.41/0.17	1.26/0.21	1.42/0.26
HHV_d(Btu/lb)	14,235/7,980	14,009/7,995	14,134/8,179
HHV_d(kJ/kg)	33,111/18,561	32,585/18,596	32,876/19,024

For test BH7/BH8/BH9, the fuel analyses were as follows:[1]

Tests BH7/BH8/BH9	Run 1 coal/bark	Run 2 coal/bark	Run 3 coal/bark
% H_2O	6.02/43.60	6.35/43.88	4.11/45.23
% Ash_d	20.96/3.84	11.23/3.98	16.98/5.14
% S_d	0.60/0.03	1.16/0.03	1.01/0.02
% N_d	1.00/0.21	1.63/0.26	1.24/0.24
HHV_d(Btu/lb)	11,820/8,180	11,320/8,330	12,120/8,260
HHV_d(kJ/kg)	27,490/19,030	30,840/19,380	28,190/19,210

[1]Subscript 'd' designates dry basis.

PLANT BH1[61]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	7/25/78	7/26/78	7/27/78	
% Isokinetic	102	99.4	99.2	
Boiler Load (% of design)	76/45	88/52	87/41	84/46
Sample Point Location	Inlet of ESP			
Stack Gas Data				
Flow (Nm^3/s-dry)	53.6	55.8	59.1	54.5
Flow (dscfm)	113,600	118,400	114,600	115,500
Temperature (°C)	170	170	164	168
Temperature (°F)	338	338	327	334
Moisture (%)	10.1	10.9	10.7	10.6
Oxygen, dry (%)	12.5	12.8	12.7	12.7
CO_2, dry (%)	7.6	7.3	7.1	7.3
Particulate Emissions				
g/Nm^3-dry	2.767	2.884	2.586	2.746
g/Nm^3-dry @ 12% CO_2	4.369	4.74	4.371	4.493
gr/dscf	1.209	1.260	1.130	1.200
gr/dscf @ 12% CO_2	1.902	2.071	1.910	1.961
ng/J	1797	1939	1720	1819
lb/10^6 Btu	4.18	4.51	4.00	4.23
Average Opacity				
Control Device				
Type	MC			
Operating Parameter[1]				
Design Parameter[1]				
Design Flow Rate (ACFM)				

[1] For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT BH2[61]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	7/25/78	7/26/78	7/26/78	
% Isokinetic	95.1	94.4	96.8	
Boiler Load (% of design)	76/45	88/52	87/41	84/46
Sample Point Location	Outlet of ESP			
Stack Gas Data				
Flow (Nm^3/s-dry)	55.4	58.0	56.7	56.5
Flow (dscfm)	117,500	123,000	119,000	119,800
Temperature (°C)	161	157	156	158
Temperature (°F)	321	314	313	316
Moisture (%)	9.6	10.5	9.8	10.0
Oxygen, dry (%)	10.4	9.4	9.9	9.9
CO_2, dry (%)	9.4	10.4	9.8	9.9
Particulate Emissions				
g/Nm^3-dry	0.007	0.012	0.008	0.009
g/Nm^3-dry @ 12% CO_2	0.008	0.014	0.009	0.010
gr/dscf	0.0029	0.0053	0.0033	0.0038
gr/dscf @ 12% CO_2	0.004	0.006	0.004	0.005
ng/J	3.4	5.8	1.1	3.4
$lb/10^6$ Btu	0.0080	0.0134	0.0026	0.0080
Average Opacity				
Control Device				
Type	MC/ESP			
Operating Parameter[1]	612	584	605	600
Design Parameter[1]	460			
Design Flow Rate (ACFM)	260,000			

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT BH3[62]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	9/24/80	9/25/80	9/25/80	
% Isokinetic	103.9	100.9	101.3	
Boiler Load (% of design)	48	49	48	48
Sample Point Location	Inlet of MC-trackside			
Stack Gas Data				
Flow (Nm^3/s-dry)	17.1	16.8	16.8	16.9
Flow (dscfm)	36,300	35,700	35,600	35,900
Temperature (°C)	205	212	208	208
Temperature (°F)	401	413	406	407
Moisture (%)	4.8	5.3	5.5	5.2
Oxygen, dry (%)	14.3	14.6	13.4	14.1
CO_2-dry (%)	6.1	5.7	7.3	6.4
Particulate Emissions				
g/Nm^3-dry	3.16	4.03	2.82	3.34
g/Nm^3-dry @ 12% CO_2	6.21	8.48	4.63	6.44
gr/dscf	1.38	1.76	1.23	1.46
gr/dscf @ 12% CO_2	2.71	3.71	2.02	2.08
ng/J	2593	3462	2025	2693
lb/10^6 Btu	6.03	8.05	4.71	6.26
Average Opacity				
Control Device				
Type				
Operating Parameter[1]				
Design Parameter[1]				
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT BH4[62]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	9/24/80	9/25/80	9/25/80	
% Isokinetic	96.3	101.0	95.0	
Boiler Load (% of design)	87	88	88	88
Sample Point Location	Inlet of MC-Riverside			
Stack Gas Data				
Flow (Nm^3/s-dry)	38.1	37.6	35.6	37.1
Flow (dscfm)	80800	79800	75400	78700
Temperature (°C)	162	167	164	164
Temperature (°F)	324	333	328	328
Moisture (%)	12.2	15.6	13.0	13.6
Oxygen, dry (%)	11.4	12.8	10.6	11.6
CO_2, dry (%)	10.5	8.6	9.9	9.7
Particulate Emissions				
g/Nm^3-dry	5.10	2.77	2.82	3.56
g/Nm^3-dry @ 12% CO_2	5.83	3.86	3.41	4.37
gr/dscf	2.23	1.21	1.23	1.56
gr/dscf @ 12% CO_2	2.55	1.69	1.49	1.91
ng/J	2911	1853	1479	2081
lb/10^6 Btu	6.77	4.31	3.44	4.84
Average Opacity				
Control Device				
Type				
Operating Parameter[1]				
Design Parameter[1]				
Design Flow Rate (ACFM)				

[1] For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT BH6 62

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	9/24/80	9/24/80	9/25/80	
% Isokinetic	106.2	105.2	103.8	
Boiler Load (% of design)				48/88
Sample Point Location	Outlet of ESP			
Stack Gas Data				
Flow (Nm^3/s-dry)	74.1	75.5	73.3	74.3
Flow (dscfm)	157,130	159,990	155,431	157,517
Temperature (°C)	129	173	168	157
Temperature (°F)	264	343	334	314
Moisture (%)	11.9	11.1	11.8	11.6
Oxygen, dry (%)	13.5	12.1	11.9	12.5
CO_2, dry (%)	7.5	8.5	6.5	7.5
Particulate Emissions				
g/Nm^3-dry	0.071	0.0297	0.0316	0.0441
g/Nm^3-dry @ 12% CO_2	0.114	0.0412	0.0583	0.0713
gr/dscf	0.031	0.013	0.0138	0.0193
gr/dscf @ 12% CO_2	0.050	0.018	0.0255	0.0312
ng/J	50.65	17.84	18.53	29.01
lb/10^6 Btu	0.1178	0.0415	0.0431	0.0675
Average Opacity				
Control Device				
Type	MC/ESP			
Operating Parameter[1]	481	430	444	452
Design Parameter[1]	460			
Design Flow Rate (ACFM)	261,000			

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT BH7.63

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	12/12/79	12/14/79	12/15/79	
% Isokinetic	96.5	105.0	96.4	
Boiler Load (% of design)	88	89	104	94
Sample Point Location	Inlet of MC-trackside			
Stack Gas Data				
Flow (Nm^3/s-dry)	24.7	21.2	21.6	22.5
Flow (dscfm)	52400	45000	45700	47700
Temperature (°C)	179	192	205	192
Temperature (°F)	355	378	401	378
Moisture (%)	6.5	4.3	6.2	5.7
Oxygen, dry (%)	11.3	10.4	10.9	10.9
CO_2, dry (%)	8.7	8.0	8.2	8.3
Particulate Emissions				
g/Nm^3-dry	8.81	7.76	8.83	8.47
g/Nm^3-dry @ 12% CO_2	12.15	11.64	12.93	12.24
gr/dscf	3.85	3.39	3.86	3.70
gr/dscf @ 12% CO_2	5.31	5.09	5.65	5.35
ng/J	4902	3939	4709	4517
lb/10^6 Btu	11.4	9.16	10.95	10.50
Average Opacity				
Control Device				
Type	MC			
Operating Parameter[1]				
Design Parameter[1]				
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT BH8[63]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	12/12/79	12/14/79	12/15/79	
% Isokinetic	98.1	106.4	96.1	
Boiler Load (% of design)	48	52	40.5	46.8
Sample Point Location	Inlet of MC-riverside			
Stack Gas Data				
Flow (Nm^3/s-dry)	29.9	27.7	25.4	27.7
Flow (dscfm)	63300	58700	53900	58600
Temperature (°C)	152	148	142	147
Temperature (°F)	305	299	287	297
Moisture (%)	6.3	13.7	12.5	10.8
Oxygen, dry (%)	14.0	14.8	11.2	13.3
CO_2‡±dry (%)	6.2	5.4	6.8	6.1
Particulate Emissions				
g/Nm^3-dry	1.83	4.74	5.01	3.86
g/Nm^3-dry @ 12% CO_2	3.54	10.53	8.85	7.64
gr/dscf	0.800	2.07	2.19	1.69
gr/dscf @ 12% CO_2	1.55	4.60	3.87	3.34
ng/J	1415	4141	2752	2769
lb/10^6 Btu	3.29	9.63	6.40	6.44
Average Opacity				
Control Device				
Type	MC			
Operating Parameter[1]				
Design Parameter[1]				
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT BH9[63]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	12/12/79	12/14/79	12/15/79	
% Isokinetic	97.4	97.5	97.7	
Boiler Load (% of design)	88/48	89/52	104/40	94/46
Sample Point Location	Outlet of ESP			
Stack Gas Data				
Flow (Nm^3/s-dry)	70.4	71.5	71.7	71.2
Flow (dscfm)	149300	151500	152100	151000
Temperature (°C)	159	154	154	156
Temperature (°F)	319	309	309	312
Moisture (%)	8.4	9.4	7.7	8.5
Oxygen, dry (%)	15.0	14.2	12.2	13.8
CO_2, dry (%)	5.4	5.3	6.9	5.9
Particulate Emissions				
g/Nm^3-dry	0.249	0.279	0.224	0.251
g/Nm^3-dry @ 12% CO_2	0.554	0.632	0.390	0.525
gr/dscf	0.109	0.122	0.098	0.110
gr/dscf @ 12% CO_2	0.242	0.276	0.170	0.229
ng/J	225	222	138	195
lb/10^6 Btu	0.524	0.517	0.320	0.454
Average Opacity				
Control Device				
Type	ESP			
Operating Parameter[1]	479	429	442	450
Design Parameter[1]	460			
Design Flow Rate (ACFM)	260,000			

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT BI[64]

Boilers No. 7 and 8 at Plant BI were tested by the EPA to obtain particulate emission data for the development of New Source Performance Standards. Both boilers are wood/coal cofired spreader stokers with a combined capacity of 565,000 pounds per hour of steam. The particulate emissions from each boiler are separately controlled by a mechanical collector followed by an ESP with two separate chambers, each chamber has one stack. The design SCA for the ESP is 300 ft^2/1000 ACFM. Fly ash collected by the mechanical collector is not reinjected.

Three EPA Method 5 test runs were performed. The average boiler load was 87 percent of rated capacity during testing. Wood supplied 25 percent of the heat input during the tests with the rest from coal. The average particulate emission rate of the two stacks was 0.0418 pounds per million Btu. The average SCA during testing based on the total air flow to the ESP unit was 320 ft^2/1000 ACFM. The data presented is the weighted average of both stacks, except for the gas flow rate which is the sum of both stacks.

The fuel analyses during testing were as follows:[1]

Test BI1	Run 1 coal/bark	Run 2 coal/bark	Run 3 coal/bark
% H_2O	4.8/45.8	5.2/48.0	6.4/44.5
% Ash_d	15.12/3.08	15.37/4.49	6.59/2.48
% S_d	0.81/0.01	1.01/0.01	0.77/0.01
% N_d	1.19/0.28	1.18/0.31	1.43/0.33
HHV_d(Btu/lb)	12,530/8,480	12,840/8,130	13,990/8,510
HHV_d(kJ/kg)	29,140/19,720	29,870/18,910	32,540/19,790

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[1]Subscript 'd' designates dry basis.

PLANT BII[64]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	2/12/80	2/13/80	2/13/80	
% Isokinetic	99.0	93.5	96.9	
Boiler Load (% of design)	87	84	90	87
Sample Point Location	Outlet of ESP			
Stack Gas Data				
Flow (Nm^3/s-dry)	91.6	100.7	100.9	97.7
Flow (dscfm)	194,200	213,500	214,000	207,200
Temperature (°C)	192	191	189	191
Temperature (°F)	378	375	372	375
Moisture (%)	12.4	11.6	11.1	11.7
Oxygen, dry (%)	8.8	11.0	10.8	10.2
CO_2, dry (%)	10.2	9.2	9.7	9.7
Particulate Emissions				
g/Nm^3-dry	0.059	0.033	0.021	0.038
g/Nm^3-dry @ 12% CO_2	0.070	0.043	0.026	0.047
gr/dscf	0.0258	0.0145	0.0092	0.0165
gr/dscf @ 12% CO_2	0.0304	0.0189	0.0114	0.0204
ng/J	25.5	17.7	10.7	18.0
$lb/10^6$ Btu	0.0593	0.0412	0.0248	0.0418
Average Opacity				
Control Device				
Type	MC/ESP			
Operating Parameter[1]	335	312	314	320
Design Parameter[1]	296			
Design Flow Rate (ACFM)	415,000			

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT BJ[65,66]

The boiler at Plant BJ was tested to determine compliance with State emission standards. The boiler is a spreader stoker rated at 600,000 pounds per hour of steam. The boiler cofires bark, sawdust, and number 6 fuel oil. Particulate emissions are controlled by a mechanical collector followed by an ESP. The ESP has a design SCA of 355 ft^2/1000 ACFM. Fly ash collected by the mechanical collector passes through a sand classifier and large particles are reinjected into the boiler furnace.

The average emission rate during testing was 0.0260 pounds per million Btu. The boiler was operated at 76 percent of rated capacity. Wood provided 64 percent of the heat input. The SCA during the test averaged 456 ft^2/1000 ACFM.

PLANT BJ1[66]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	6/27/79	6/27/79	6/27/79	
% Isokinetic	105	106	106	
Boiler Load (% of design)				76
Sample Point Location	Outlet of ESP			
Stack Gas Data				
Flow (Nm^3/s-dry)	69.1	66.2	66.6	67.3
Flow (dscfm)	146,400	140,400	141,100	142,600
Temperature (°C)	196	195	198	196
Temperature (°F)	385	383	389	386
Moisture (%)	15.0	15.0	14.0	14.7
Oxygen, dry (%)	6.9	6.0	5.7	6.2
CO_2, dry (%)	12.1	11.5	11.8	11.8
Particulate Emissions				
g/Nm^3-dry	0.032	0.030	0.030	0.032
g/Nm^3-dry @ 12% CO_2	0.032	0.032	0.030	0.032
gr/dscf	0.014	0.013	0.013	0.014
gr/dscf @ 12% CO_2	0.014	0.014	0.013	0.014
ng/J	12.5	10.8	10.3	11.2
lb/10^6 Btu	0.029	0.025	0.024	0.026
Average Opacity	0	0	0	0
Control Device				
Type	MC/ESP			
Operating Parameter[1]	443	463	462	456
Design Parameter[1]	356			
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT BK[67,68]

Plant BK was tested to determine compliance with North Carolina particulate emission standards. This plant has a firetube boiler and is rated at 3,400 pounds of steam per hour. Particulates are controlled with a mechanical collector. Fly ash collected by the mechanical collector is not reinjected. Wood chips and dust are fed by an automatic drop-chute into the boiler and large scraps are manually stoked.

Three EPA Method 5 test runs were performed. Run 3 is not shown because test difficulties were incurred during Run 3 and consequently the results for that run are not representative of the facility. The average particulate emission rate for Plant BK was 0.448 pounds per million Btu.

PLANT BK1[68]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	5/2/78	5/2/78		
% Isokinetic	97.4	99.6		
Boiler Load (% of design)	39	41		40
Sample Point Location				
Stack Gas Data				
Flow (Nm^3/s-dry)	1.47	1.49		1.48
Flow (dscfm)	3.123	3.158		3.140
Temperature (°C)	155	151		153
Temperature (°F)	311	304		308
Moisture (%)	2.8	2.5		2.6
Oxygen, dry (%)	18.6	18.5		18.6
CO_2, dry (%)	2.2	2.2		2.2
Particulate Emissions				
g/Nm^3-dry	0.117	0.048		0.082
g/Nm^3-dry @ 12% CO_2	0.636	0.261		0.448
gr/dscf	0.051	0.021		0.036
gr/dscf @ 12% CO_2	0.278	0.114		0.196
ng/J	276.9	108.4		192.6
lb/10^6 Btu	0.644	0.252		0.448
Average Opacity				
Control Device				
Type	MC			
Operating Parameter[1]				
Design Parameter[1]				
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT BL[69,70]

Plant BL was tested to determine compliance with State emission regulations. Plant BL has an overfeed inclined grate wood-fired stoker boiler. The boiler fires a mixture of bark, shavings, and sawdust. Particulate emissions are controlled by a multiclone. Fly ash collected by the multiclone is not reinjected.

The boiler was operated at an average of 42 percent of capacity during testing. The average emission rate was 0.742 pounds per million Btu.

PLANT BL1[70]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	7/24/79	7/24/79	7/24/79	
% Isokinetic	106	99	102	
Boiler Load (% of design)	43	39	45	42
Sample Point Location	outlet of MC			
Stack Gas Data				
Flow (Nm^3/s-dry)	1.16	1.20	1.17	1.18
Flow (dscfm)	2,453	2,549	2,475	2,492
Temperature (°C)	163	164	157	161
Temperature (°F)	325	328	315	323
Moisture (%)	9.9	7.7	11.1	9.6
Oxygen, dry (%)	13.0	13.8	12.7	13.2
CO_2, dry (%)	7.0	6.4	7.5	7.0
Particulate Emissions				
g/Nm^3-dry	0.448	0.446	0.508	0.467
g/Nm^3-dry @ 12% CO_2	0.769	0.837	0.812	0.806
gr/dscf	0.196	0.195	0.222	0.204
gr/dscf @ 12% CO_2	0.336	0.366	0.355	0.352
ng/J	299	332	327	319
lb/10^6 Btu	0.696	0.771	0.760	0.742
Average Opacity				
Control Device				
Type	MC			
Operating Parameter[1]				
Design Parameter[1]				
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT BM[71,72,73]

Plant BM was tested to determine compliance with State emission regulations. Plant BM has a wood/coal cofired firetube boiler rated at 8,200 pounds per hour of steam. Particulate emissions are controlled by a mechanical collector. All of the flyash collected by the mechanical collector is reinjected into the boiler furnace.

The boiler was operated at an average of 102 percent of capacity during testing. The operation rate was determined from the calculated heat input and the rated heat input since no steam flow data were available. Particulate emissions averaged 0.208 pounds per million Btu. Coal provided 9 percent of the heat input during testing.

PLANT BM1[73]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	11/29/78	11/29/78	11/29/78	
% Isokinetic	105	108	105	
Boiler Load (% of design)	97	103	106	102
Sample Point Location	outlet of MC			
Stack Gas Data				
Flow (Nm^3/s-dry)	3.17	3.11	3.15	3.14
Flow (dscfm)	6,714	6,584	6,680	6,659
Temperature (°C)	260	261	263	262
Temperature (°F)	500	502	506	503
Moisture (%)	5.6	5.5	6.4	5.8
Oxygen, dry (%)	14.8	14.3	14.1	14.4
CO_2, dry (%)	5.8	6.4	6.7	6.3
Particulate Emissions				
g/Nm^3-dry	0.109	0.106	0.108	0.108
g/Nm^3-dry @ 12% CO_2	0.224	0.198	0.193	0.205
gr/dscf	0.0477	0.0461	0.0471	0.0470
gr/dscf @ 12% CO_2	0.0980	0.0864	0.0844	0.0896
ng/J	95.5	87.3	85.1	89.3
lb/10^6 Btu	0.222	0.203	0.198	0.208
Average Opacity				
Control Device				
Type	MC			
Operating Parameter[1]				
Design Parameter[1]				
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT BN[74,75]

Plant BN was tested to determine compliance with State emission standards. Plant BN has a wood-fired firetube boiler rated at 26,000 pounds per hour of steam. The fuel is scraps of kiln dried wood. Particulate emissions are controlled by a mechanical collector. All of the fly ash collected by the mechanical collector is reinjected into the boiler furnace. The boiler was operated at an average of 50 percent of capacity during testing. The operating rate was determined by the heat input calculated using the F-factor and the rated heat input. No steam flow data was available. The average emission rate was 0.434 pounds per million Btu.

PLANT BN[75]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	3/18/80	3/18/80	3/18/80	
% Isokinetic	102	107	103	
Boiler Load (% of design)	54	50	45	50
Sample Point Location	outlet of MC			
Stack Gas Data				
Flow (Nm^3/s-dry)	6.38	6.56	6.46	6.51
Flow (dscfm)	13,513	13,886	13,967	13,789
Temperature (°C)	261	246	240	249
Temperature (°F)	502	474	464	480
Moisture (%)	4.0	3.6	3.4	3.7
Oxygen, dry (%)	15.1	16.5	16.8	16.1
CO_2, dry (%)	4.8	3.8	3.7	4.1
Particulate Emissions				
g/Nm^3-dry	0.160	0.216	0.141	0.172
g/Nm^3-dry @ 12% CO_2	0.400	0.683	0.458	0.512
gr/dscf	0.0701	0.0944	0.0618	0.0754
gr/dscf @ 12% CO_2	0.175	0.298	0.200	0.224
ng/J	141	242	177	187
$lb/10^6$ Btu	0.327	0.563	0.412	0.434
Average Opacity				
Control Device				
Type	MC			
Operating Parameter[1]				
Design Parameter[1]				
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

C.1.2 Bagasse-Fired Boilers

The following facility descriptions are particulate emission data for bagasse-fired boilers. Each site is given a 2-letter plant designation beginning with the letter D. This letter indicates the facility has a bagasse-fired boiler. A number after the plant description distinguishes between different tests at the same plant. Most of the tests were performed on bagasse-fired boilers in Florida. However, the method of calculation of pounds per million Btu for the State of Florida is different from the F factor method used in this report. Thus calculated emission rates in this report for the tests from Florida do not necessarily indicate compliance or noncompliance with the Florida standards.

PLANT DA[76,77]

Boiler No. 3 at Plant DA was tested to determine compliance with Florida emission standards. Boiler No. 3 is a bagasse-fired horseshoe boiler rated at 125,000 pounds per hour of steam. Particulate emissions are controlled by two impingement wet scrubbers in parallel. The normal pressure drop is 5 to 7 inches of water.

Three EPA Method 5 test runs were performed. The average boiler load was 78 percent of rated capacity. During the test, bagasse supplied an average of 92 percent of the total heat input. The average particulate emissions were 0.330 pounds per million Btu. The pressure drop during the test was normal. Results for this test are shown under the designation DA1.

Boiler No.4 at Plant DA was tested to determine the compliance with Flordia emission standards. Boiler No. 4 is a bagasse-fired horseshoe boiler rated at 125,000 pounds per hour of steam. Particulate emissions are controlled by an impingement wet scrubber. The normal operating pressure drop is 5 to 7 inches of water.

Three EPA Method 5 test runs were performed. The average boiler load during the tests was 71 percent of rated capacity. The average particulate emission rate was 0.263 pounds per million Btu. The scrubber pressure drop during testing was normal. Results for this test are shown under the designation DA2.

PLANT DA1[76]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	1/29/79	1/29/79	1/29/79	
% Isokinetic	98.7	97.9	100.2	
Boiler Load (% of design)	79	74	80	78
Sample Point Location	Outlet of Scrubber			
Stack Gas Data				
Flow (Nm^3/s-dry)	22.3	29.9	28.3	26.8
Flow (dscfm)	47,200	63,400	60,100	56,900
Temperature (°C)	64.7	63.3	63.6	63.9
Temperature (°F)	148.4	146.0	146.5	147.0
Moisture (%)	22.3	22.0	23.0	22.6
Oxygen, dry (%)	10.0	13.5	12.8	12.1
CO_2, dry (%)	9.0	6.3	7.0	7.4
Particulate Emissions				
g/Nm^3-dry	0.270	0.231	0.213	0.238
g/Nm^3-dry @ 12% CO_2	0.359	0.439	0.364	0.387
gr/dscf	0.118	0.101	0.093	0.103
gr/dscf @ 12% CO_2	0.157	0.192	0.159	0.169
ng/J	128.1	161.7	135.9	141.9
$lb/10^6$ Btu	0.298	0.376	0.316	0.330
Average Opacity				
Control Device				
Type	2WS			
Operating Parameter[1]				5-7
Design Parameter[1]	5-7			
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT DA2 77

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	12/20/78	12/20/78	12/21/78	
% Isokinetic	101.7	95.4	103.8	
Boiler Load (% of design)	70	74	69	71
Sample Point Location	Outlet of Scrubber			
Stack Gas Data				
Flow (Nm^3/s-dry)	28.4	27.5	27.4	27.7
Flow (dscfm)	60,300	58,200	58,000	58,800
Temperature (°C)	66	65	69	67
Temperature (°F)	151	149	156	152
Moisture (%)	24.8	26.3	25.5	25.5
Oxygen, dry (%)	13.3	10.8	11.2	11.8
CO_2, dry (%)	6.7	9.0	8.8	8.2
Particulate Emissions				
g/Nm^3-dry	0.190	0.220	0.185	0.198
g/Nm^3-dry @ 12% CO_2	0.341	0.293	0.252	0.295
gr/dscf	0.083	0.096	0.081	0.087
gr/dscf @ 12% CO_2	0.149	0.128	0.110	0.129
ng/J	129.4	112.7	98.9	113.7
lb/10^6 Btu	0.301	0.262	0.230	0.263
Average Opacity				
Control Device				
Type	WS			
Operating Parameter[1]				5-7
Design Parameter[1]	5-7			
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT DC[78,79]

Plant DC was tested to determine particulate emissions levels. Plant DC has a bagasse-fired spreader stoker boiler rated at 312,000 pounds per hour of steam. Particulate emissions are controlled by a mechanical collector followed by a variable throat ejector venturi wet scrubber equipped with a demister. The normal scrubber flue gas pressure drop is 2 inches of water. However, for this scrubber type gas phase pressure drop is not a good indicator of scrubber efficiency (see Section 4.1.2.3). This scrubber would be equivalent in removal efficiency to a standard venturi scrubber with a flue gas pressure drop of 6 inches of water.

Three EPA Method 5 test runs were performed. The average boiler load during the test was 93 percent of rated capacity. The average emissions were 0.084 pounds per million Btu. The scrubber pressure drop during testing was normal.

For test DC1, the fuel analyses were as follows:[1]

Test DC1	Run 1	Run 2	Run 3
% H_2O	48.25	47.05	48.83
% Ash_d	3.40	3.08	2.61

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[1] Subscript 'd' designates dry basis.

PLANT DC179

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	5/24/79	5/24/79	5/24/79	
% Isokinetic	92.7	97.1	102.4	
Boiler Load (% of design)	92	94	93	93
Sample Point Location	Outlet of Scrubber			
Stack Gas Data				
Flow (Nm^3/s-dry)	45.6	46.2	45.2	45.7
Flow (dscfm)	96,720	97,860	95,890	96,820
Temperature (°C)	74	72	74	73
Temperature (°F)	165	161	166	164
Moisture (%)	33.7	33.6	35.4	34.2
Oxygen, dry (%)	5.8	8.6	6.8	7.1
CO_2, dry (%)	14.2	11.4	13.5	13.0
Particulate Emissions				
g/Nm^3-dry	0.082	0.089	0.119	0.097
g/Nm^3-dry @ 12% CO_2	0.071	0.094	0.106	0.090
gr/dscf	0.036	0.039	0.052	0.042
gr/dscf @ 12% CO_2	0.031	0.041	0.046	0.039
ng/J	28.4	37.4	43.4	36.4
lb/10^6 Btu	0.066	0.087	0.101	0.084
Average Opacity				
Control Device				
Type	MC/WS			
Operating Parameter[1]				2
Design Parameter[1]				
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT DD[80]

Boiler No. 2 at Plant DD was tested to determine the particulate emission rate. Boiler No. 2 is a bagasse-fired spreader stoker boiler rated at 288,000 pounds per hour of steam. Particulate emissions are controlled by two mechanical collectors in series.

Three EPA Method 5 test runs were performed. The average boiler load was 68 percent of rated capacity during testing. The average particulate emissions were 0.285 pounds per million Btu.

For test DD1, the fuel analyses were as follows:

Test DD1	Run 1	Run 2	Run 3
% H_2O	48.7	48.2	48.8

PLANT DD1 80

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	12/16/78	12/16/78	12/17/78	
% Isokinetic	98.9	102.8	90.4	
Boiler Load (% of design)	67	70	68	68
Sample Point Location	Outlet of MC			
Stack Gas Data				
Flow (Nm^3/s-dry)	39.7	39.2	41.7	40.2
Flow (dscfm)	84,200	83,100	88,500	85,300
Temperature (°C)	164	158	158	160
Temperature (°F)	327	316	316	320
Moisture (%)	23.9	25.6	25.3	24.9
Oxygen, dry (%)	7.3	9.3	9.5	8.7
CO_2, dry (%)	11.9	10.5	10.2	10.9
Particulate Emissions				
g/Nm^3-dry	0.316	0.307	0.242	0.288
g/Nm^3-dry @ 12% CO_2	0.318	0.350	0.286	0.318
gr/dscf	0.138	0.134	0.106	0.126
gr/dscf @ 12% CO_2	0.139	0.153	0.125	0.139
ng/J	120.0	137.2	110.5	122.6
lb/10^6 Btu	0.279	0.319	0.257	0.285
Average Opacity	20.3	18.6	17.0	18.6
Control Device				
Type	2MC			
Operating Parameter[1]				
Design Parameter[1]				
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT DE[81-84]

Boiler No. 6 at Plant DE was tested to determine compliance with Florida emission standards. Boiler No. 6 is a bagasse-fired fuel cell rated at 125,000 pounds per hour of steam. Particulate emissions are controlled with an impingement wet scrubber. The normal scrubber pressure drop is 6 inches of water.

Three EPA Method 5 test runs were performed. The average boiler load was 96 percent of rated capacity. During the test, bagasse supplied an average of 94 percent of the heat input. The average particulate emissions were 0.29 pounds per million Btu. During the tests, the scrubber pressure drop was normal. These test results are summarized under the designation DE1.

Boiler No. 12 at Plant DE was tested to determine compliance with Florida emission standards. Boiler No. 12 is a bagasse-fired spreader stoker rated at 150,000 pounds per hour of steam. Particulate emissions are controlled by a mechanical collector followed by an impingement wet scrubber. The normal scrubber pressure drop is 6 inches of water.

Three EPA Method 5 test runs were performed. The average boiler load was 92 percent of rated capacity during testing. The average particulate emissions were 0.269 pounds per million Btu. The scrubber pressure drop was normal. These test results are summarized under the designation DE2.

Boiler No. 14 at Plant DE3 was tested to determine compliance with Florida emission standards. Boiler No. 14 is a bagasse-fired spreader stoker boiler rated at 150,000 pounds per hour of steam. Particulate emissions are controlled by a mechanical collector followed by an impingement wet scrubber. The normal pressure drop is 6 inches of water.

Three EPA Method 5 test runs were performed. The average boiler load was 98 percent of rated capacity during testing. The average particulate emission rate was 0.236 pounds per million Btu. The scrubber pressure drop was normal during the tests. The results of this test are summarized under the designation DE3.

PLANT DE1 82

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	11/19/79	11/19/79	11/19/79	
% Isokinetic	96.4	94.9	92.9	
Boiler Load (% of design)	93	96	98	96
Sample Point Location	Outlet of Scrubber			
Stack Gas Data				
Flow (Nm^3/s-dry)	25.4	24.8	28.9	26.4
Flow (dscfm)	53,900	52,500	61,300	55,900
Temperature (°C)	76.6	76.9	77.2	76.9
Temperature (°F)	169.8	170.4	171.0	170.4
Moisture (%)	27.0	29.4	26.9	27.8
Oxygen, dry (%)	11.2	10.5	11.3	11.0
CO_2, dry (%)	10.5	10.2	9.5	10.1
Particulate Emissions				
g/Nm^3-dry	0.245	0.222	0.242	0.236
g/Nm^3-dry @ 12% CO_2	0.279	0.261	0.307	0.282
gr/dscf	0.107	0.097	0.106	0.104
gr/dscf @ 12% CO_2	0.122	0.114	0.134	0.123
ng/J	131.6	110.9	131.6	124.7
lb/10^6 Btu	0.306	0.258	0.306	0.290
Average Opacity				
Control Device				
Type	WS			
Operating Parameter[1]				6
Design Parameter[1]				
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT DE2 83

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	2/7/80	2/7/80	2/7/80	
% Isokinetic	92.8	91.6	93.4	
Boiler Load (% of design)	93	91	93	92
Sample Point Location	Outlet of Scrubber			
Stack Gas Data				
Flow (Nm^3/s-dry)	25.1	26.6	30.0	25.9
Flow (dscfm)	53,200	56,300	55,000	54,800
Temperature (°C)	72	72	73	72
Temperature (°F)	162	161	163	162
Moisture (%)	27.4	26.9	28.3	27.5
Oxygen, dry (%)	5.0	4.8	4.8	4.8
CO_2, dry (%)	15.8	13.2	13.5	14.2
Particulate Emissions				
g/Nm^3-dry	0.396	0.332	0.352	0.360
g/Nm^3-dry @ 12% CO_2	0.300	0.302	0.314	0.305
gr/dscf	0.173	0.145	0.154	0.157
gr/dscf @ 12% CO_2	0.131	0.132	0.137	0.133
ng/J	128.6	106.2	112.7	115.8
lb/10^6 Btu	0.299	0.247	0.262	0.269
Average Opacity				
Control Device				
Type	MC/WS			
Operating Parameter[1]				6
Design Parameter[1]				
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	1/3/80	1/3/80	1/3/80	
% Isokinetic	105.0	95.9	99.4	
Boiler Load (% of design)	95	98	100	98
Sample Point Location	Outlet of Scrubber			
Stack Gas Data				
Flow (Nm^3/s-dry)	23.7	24.2	23.7	23.9
Flow (dscfm)	50,200	51,400	50,300	50,600
Temperature (°C)	71	72	72	72
Temperature (°F)	160.5	162	162	162
Moisture (%)	32.8	32.5	33.2	32.8
Oxygen, dry (%)	5.8	6.5	5.5	5.9
CO_2, dry (%)	14.0	13.8	15.0	14.3
Particulate Emissions				
g/Nm^3-dry	0.284	0.295	0.302	0.294
g/Nm^3-dry @ 12% CO_2	0.242	0.256	0.242	0.247
gr/dscf	0.124	0.129	0.132	0.128
gr/dscf @ 12% CO_2	0.106	0.112	0.106	0.108
ng/J	97.2	105.8	101.5	101.5
lb/10^6 Btu	0.226	0.246	0.236	0.236
Average Opacity				
Control Device				
Type	MC/WS			
Operating Parameter[1]				6
Design Parameter[1]				
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT DF[85]

Boiler No. 2 at Plant DF was tested to determine compliance with Florida emission standards. Boiler No. 2 is a bagasse-fired horseshoe boiler rated at 125,000 pounds per hour of steam. Particulate emissions are controlled by two impingement wet scrubbers in parallel. The normal scrubber pressure drop is 8 to 9 inches of water.

Three EPA Method 5 test runs were performed. The average boiler load was 71 percent of rated capacity during testing. The average particulate emission rate was 0.279 pounds per million Btu. The scrubber pressure drop was normal.

PLANT DF1[85]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	12/19/79	12/19/79	12/19/79	
% Isokinetic	99.1	99.6	97.1	
Boiler Load (% of design)	73	72	69	71
Sample Point Location	Outlet of Scrubber			
Stack Gas Data				
Flow (Nm^3/s-dry)	35.0	28.9	31.7	31.9
Flow (dscfm)	74,100	61,300	67,200	67,600
Temperature (°C)	70.0	71.1	66.9	69.3
Temperature (°F)	158	160	152.4	156.8
Moisture (%)	26.6	26.7	25.2	26.2
Oxygen, dry (%)	12.1	11.0	10.2	11.3
CO_2, dry (%)	8.6	9.1	8.1	8.6
Particulate Emissions				
g/Nm^3-dry	0.220	0.263	0.190	0.224
g/Nm^3-dry @ 12% CO_2	0.307	0.348	0.281	0.312
gr/dscf	0.096	0.115	0.083	0.098
gr/dscf @ 12% CO_2	0.134	0.152	0.123	0.136
ng/J	129.0	137.6	92.4	119.7
lb/10^6 Btu	0.300	0.320	0.215	0.279
Average Opacity				
Control Device				
Type	2WS			
Operating Parameter[1]				8-9
Design Parameter[1]				
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT DG[86]

Boiler No. 5 at Plant DG was tested to determine compliance with Florida particulate emissions standards. Boiler No.5 is a bagasse-fired spreader stoker rated at 160,000 pounds per hour of steam. Particulate emissions are controlled with two impingement wet scrubbers in parallel. The normal pressure drop is 5 to 9 inches of water.

Three EPA Method 5 test runs were performed. The average boiler load was 103 percent of rated capacity. During the test, bagasse supplied 80 percent of the heat input. The average particulate emission rate was 0.108 pounds per million Btu. The scrubber pressure drop during the test was normal.

PLANT DG1 86

TEST SUMMARY SHEETS
(Particulates only)

Test Number	One	Two	Three	Average
General Data				
Date	10/25/79	10/25/79	10/26/79	
% Isokinetic	101.6	101.3	102.1	101.7
Boiler Load (% of design)	103	101	106	103
Sample Point Location	Outlet of scrubber			
Stack Gas Data				
Flow (Nm^3/s-dry)	28.2	29.1	27.7	28.3
Flow (dscfm)	59,800	61,700	58,700	60,100
Temperature (°C)	62.6	62.2	63.8	62.9
Temperature (°F)	144.6	143.9	146.9	145.1
Moisture (%)	21.7	21.7	23.4	22.2
Oxygen, dry (%)	8.3	8.0	8.9	8.4
CO_2, dry (%)	11.0	10.5	11.3	10.9
Particulate Emissions				
g/Nm^3-dry	0.124	0.119	0.094	0.112
g/Nm^3-dry @ 12% CO_2	0.135	0.135	0.101	0.124
gr/dscf	0.054	0.052	0.041	0.049
gr/dscf @ 12% CO_2	0.059	0.059	0.044	0.054
ng/J	50.7	48.2	40.0	46.3
lb/10^6 Btu	0.118	0.112	0.093	0.108
Average Opacity				
Control Device				
Type	2WS			
Operating Parameter[1]				5-9
Design Parameter[1]				
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT DH[87,88]

Boiler No.5 at plant DH was tested to determine compliance with Florida particulate emissions standards. Boiler No.5 is a spreader stoker rated at 200,000 pounds per hour of steam. Bagasse is the principal fuel supplemented with No.6 fuel oil. Particulate emissions are controlled by an impingement wet scrubber. The normal scrubber pressure drop is 6 inches of water.

Three EPA Method 5 test runs were performed. The average boiler load was 82 percent of rated capacity. The average particulate emission rate was 0.140 pounds per million Btu. The scrubber pressure drop during the test was normal. The results of this test are summarized under the designation DH1.

Boiler No. 2 at plant DH was tested by the EPA to obtain particulate emission data for the development of New Source Performance Standards. Boiler No. 2 is a spreader stoker rated at 150,000 pounds per hour of steam. Particulate emissions are controlled by an impingement wet scrubber. The normal scrubber pressure drop is 6 inches of water.

Three EPA Method 5 test runs were performed. The average boiler load was 97 percent of rated capacity. The average particulate emission rate was 0.270 pounds per million Btu. During the test the scrubber pressure drop was normal. The results of this test are summarized under the designation DH2.

The fuel analyses during testing were as follows:[1]

Test DH2	Run 1	Run 2	Run 3
% H_2O	57.1	60.4	57.7
% Ash_d	1.09	2.85	1.58
% S_d	0.01	0.01	0.01
% N_d	0.36	0.39	0.40
HHV_d(Btu/lb)	7,939	8,101	8,233
HVV_d(kJ/kg)	18,470	18,840	19,150

[1]Subscript 'd' designates dry basis.

PLANT DH1 87

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	2/29/80	2/29/80	2/29/80	
% Isokinetic	91.8	99.4	103.1	
Boiler Load (% of design)	85	78	83	82
Sample Point Location	Outlet of scrubber			
Stack Gas Data				
Flow (Nm^3/s-dry)	49.7	56.1	55.5	53.8
Flow (dscfm)	105,300	119,000	117,700	114,000
Temperature (°C)	65.9	65.7	66.4	66.0
Temperature (°F)	150.7	150.3	151.5	150.8
Moisture (%)	25.7	25.1	26.3	25.7
Oxygen, dry (%)	10.1	10.9	10.6	10.5
CO_2, dry (%)	10.4	9.6	10.0	10.0
Particulate Emissions				
g/Nm^3-dry	0.149	0.098	0.117	0.121
g/Nm^3-dry @ 12% CO_2	0.172	0.124	0.140	0.145
gr/dscf	0.065	0.043	0.051	0.053
gr/dscf @ 12% CO_2	0.075	0.054	0.061	0.063
ng/J	71.0	51.6	58.5	60.4
lb/10^6 Btu	0.165	0.120	0.136	0.140
Average Opacity				
Control Device				
Type	WS			
Operating Parameter[1]				6
Design Parameter[1]				
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT DH2 88

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	12/17/79	12/18/79	12/18/79	
% Isokinetic	106	106	102	
Boiler Load (% of design)	95	101	96	97
Sample Point Location	Outlet of scrubber			
Stack Gas Data				
Flow (Nm^3/s-dry)	27.6	27.7	27.7	27.7
Flow (dscfm)	58,500	58,700	58,800	58,700
Temperature (°C)	72	73	72	72
Temperature (°F)	161	164	162	162
Moisture (%)	31.3	33.1	31.7	32.0
Oxygen, dry (%)	9.2	9.0	9.4	9.2
CO_2, dry (%)	10.8	11.1	11.3	11.1
Particulate Emissions				
g/Nm^3-dry	0.297	0.229	0.261	0.262
g/Nm^3-dry @ 12% CO_2	0.330	0.247	0.275	0.284
gr/dscf	0.130	0.100	0.114	0.114
gr/dscf @ 12% CO_2	0.144	0.108	0.120	0.124
ng/J	131.6	99.8	117.0	116.1
lb/10^6 Btu	0.306	0.232	0.272	0.270
Average Opacity				
Control Device				
Type	2 WS			
Operating Parameter[1]				6
Design Parameter[1]				
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

C.1.3 MSW-Fired Boilers

The following facility descriptions and particulate emission data are for MSW-fired boilers. Each site is given a 2-letter plant designation beginning with the letter F. This letter indicates the facility has a MSW-fired boiler. A number after the plant designation distinguishes between different tests at the same plant.

PLANT FA[89,90]

Plant FA was tested to determine if it was able to meet Massachusetts' particulate emissions standards when the fuel feed rate to one of the boilers was increased beyond the design capacity. Plant FA has two overfeed water wall MSW-fired boilers rated at 30,000 pounds per hour of steam capacity and 5 tons per hour of refuse feed rate each. Each boiler is equipped with its own ESP. The ESPs are exhausted through a common stack. The design SCA of the ESPs is 126 ft^2/1000 ACFM.

Three EPA Method 5 test runs were made. During the test, boiler No.2 was operated with a feed rate of 8 tons per hour of refuse and the boiler load was 88 percent of rated steam capacity. Boiler No.1 was shutdown. The load factor for the boiler was based on the fuel fired rate because it was being operated outside its design range. The average particulate emissions were 0.200 pounds per million Btu. The average SCA during the tests was 139 ft^2/1000 ACFM.

PLANT FA1[90]

TEST SUMMARY SHEETS
(Particulates only)

Test Number	One	Two	Three	Average
General Data				
Date	8/17/78	8/17/78	8/17/78	
% Isokinetic	104.2	101.3	101.8	
Boiler Load (% of design)	160	160	160	160*
Sample Point Location	Outlet of ESP			
Stack Gas Data				
Flow (Nm^3/s-dry)	8.2	7.9	8.5	8.2
Flow (dscfm)	17,350	16,730	18,030	17,370
Temperature (°C)	210.8	212	203	208
Temperature (°F)	411.4	413.0	397.0	407.1
Moisture (%)	15.2	14.0	16.0	15.1
Oxygen, dry (%)	13.0	13.0	12.8	12.9
CO_2, dry (%)	7.0	6.8	7.2	7.0
Particulate Emissions				
g/Nm^3-dry	0.167	0.103	0.108	0.126
g/Nm^3-dry @ 12% CO_2	0.286	0.181	0.178	0.215
gr/dscf	0.073	0.045	0.047	0.055
gr/dscf @ 12% CO_2	0.125	0.079	0.078	0.094
ng/J	114.4	71.8	71.8	86.0
lb/10^6 Btu	0.266	0.167	0.167	0.200
Average Opacity				
Control Device				
Type	ESP			
Operating Parameter[1]	138	145	134	139
Design Parameter[1]	126			
Design Flow Rate (ACFM)	32,000			

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.
*Based on fuel feed rate.

PLANT FB[91-93]

Boiler No. 1 at Plant FB was tested to determine the particulate emission rate. Boiler No. 1 is an overfeed stoker fired by 100 percent municipal solid waste and is rated at 135,000 pounds per hour of steam. Particulate emissions are controlled by an ESP. The design SCA of the ESP is 316 ft^2/1000 ACFM.

Three EPA Method 5 test runs were performed. The average boiler load was 77 percent of rated capacity during testing. The average particulate emission rate was 0.0465 pounds per million Btu. The SCA during the test averaged 573 ft^2/1000 ACFM.

PLANT FB1 93

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	9/22/76	9/22/76	9/23/76	
% Isokinetic	103.6	102	98.5	
Boiler Load (% of design)	78	77	76	77
Sample Point Location	Outlet of ESP			
Stack Gas Data				
Flow (Nm^3/s-dry)	17.6	18.3	23.9	20.0
Flow (dscfm)	37,380	38,720	50,750	42,280
Temperature (°C)	168	178	191	179
Temperature (°F)	335	352	375	354
Moisture (%)	20.2	17.6	14.3	17.4
Oxygen, dry (%)	7.9	8.6	11.0	9.2
CO_2, dry (%)	10.0	10.0	8.0	9.3
Particulate Emissions				
g/Nm^3-dry	0.053	0.053	0.028	0.044
g/Nm^3-dry @ 12% CO_2	0.062	0.064	0.041	0.056
gr/dscf	0.023	0.023	0.012	0.019
gr/dscf @ 12% CO_2	0.027	0.028	0.018	0.024
ng/J	21.5	22.8	15.5	19.9
lb/10^6 Btu	0.050	0.053	0.036	0.046
Average Opacity				
Control Device				
Type	MC/ESP			
Operating Parameter[1]	630	616	474	573
Design Parameter[1]	316			
Design Flow Rate (ACFM)	140,000			

[1] For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT FC[94,95]

Plant FC was tested to determine compliance with State and Federal particulate emissions standards. Plant FC has two identical overfeed stoker boilers rated at 175,000 pounds per hour of steam each. They are designed to burn 1200 tons per day of municipal solid waste. The flue gases from the boilers pass through individual ESPs and are combined in a single stack. The design SCA of the ESPs is 209 ft^2/1000 ACFM.

Three EPA Method 5 test runs were performed at the stack. The first run was deleted due to a bad leak check. Both boilers were operating and the average load was 84 percent of rated capacity. The average particulate emission rate was 0.087 pounds per million Btu which was below both the State allowable of 0.0915 pounds per million Btu and the Federal allowable (40 CFR 60 Subpart E) of 0.146 pounds per million Btu. The average SCA during the test was 243 ft^2/1000 ACFM.

PLANT FC1 95

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	____	6/8/76	6/8/76	
% Isokinetic	____	99	99	
Boiler Load (% of design)	____	81/90	80/85	80/88
Sample Point Location	Combined outlet of ESPs			
Stack Gas Data				
Flow (Nm^3/s-dry)	____	78.5	76.0	77.2
Flow (dscfm)	____	166,400	161,000	163,700
Temperature (°C)	____	264	258	261
Temperature (°F)	____	508	497	502
Moisture (%)	____	12.0	14.1	13.0
Oxygen, dry (%)	____	10.0	9.8	9.9
CO_2, dry (%)	____	8.5	8.6	8.6
Particulate Emissions				
g/Nm^3-dry	____	0.080	0.073	0.076
g/Nm^3-dry @ 12% CO_2	____	0.112	0.101	0.106
gr/dscf	____	0.035	0.032	0.034
gr/dscf @ 12% CO_2	____	0.049	0.044	0.046
ng/J	____	39.6	35.3	37.4
lb/10^6 Btu	____	0.092	0.082	0.087
Average Opacity	____	____	____	____
Control Device				
Type	2 ESPs			
Operating Parameter[1]	____	240	246	243
Design Parameter[1]	209			
Design Flow Rate (ACFM)	2 x 200,000			

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT FD[96-98]

The East and West boilers at Plant FD were tested to determine the particulate emission rate. Both are MSW-fired ram-fed controlled air boilers. They are rated at 10,000 pounds per hour of steam each. No add-on controls are used.

Two EPA Method 5 tests were run on the East boiler. No steam generation rates were reported, so the steam generation rate was estimated based on the mass emission rate and the emission rate calculated using the F-factor. The average particulate emission rate for the East boiler was 0.195 pounds per million Btu for the first test (FD1) and 0.259 pounds per million Btu for the second test (FD2). During test FD1 the composite moisture of the fuel was 15.2 percent and the fuel heating value was 4,670 Btu/lb.

This plant was later retested by the EPA as part of the standards development program. The West boiler operated at an average of 76 percent of rated capacity during testing. The average particulate emission rate for the West boiler was 0.251 pounds per million Btu.

PLANT FDI 96

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	2/22/79	2/22/79	3/06/79	
% Isokinetic	108.6	101.5	108.0	
Boiler Load (% of design)	85	96	89	88
Sample Point Location	East Stack			
Stack Gas Data				
Flow (Nm^3/s-dry)	3.0	3.2	2.8	3.0
Flow (dscfm)	6,300	6,750	5,940	6,330
Temperature (°C)	196	191	188	192
Temperature (°F)	384	376	371	377
Moisture (%)	15.1	13.3	17.6	15.3
Oxygen, dry (%)	12.3	11.8	12.0	12.0
CO_2, dry (%)	6.4	7.0	7.1	6.8
Particulate Emissions				
g/Nm^3-dry	0.094	0.130	0.190	0.138
g/Nm^3-dry @ 12% CO_2	0.174	0.222	0.323	0.240
gr/dscf	0.041	0.057	0.083	0.060
gr/dscf @ 12% CO_2	0.076	0.097	0.141	0.105
ng/J	58.9	77.4	115.2	83.8
lb/10^6 Btu	0.137	0.180	0.268	0.195
Average Opacity				
Control Device				
Type	NONE			
Operating Parameter[1]				
Design Parameter[1]				
Design Flow Rate (ACFM)				

[1] For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM. For FF, A/C = ft/min.

PLANT FD2 97

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	6/15/79	6/15/79	6/15/79	
% Isokinetic	98.6	106.9	105.0	
Boiler Load (% of design)	78	62	87	76
Sample Point Location	East Stack			
Stack Gas Data				
Flow (Nm^3/s-dry)	3.4	2.9	3.4	3.3
Flow (dscfm)	7,340	6,240	7,300	6,960
Temperature (°C)	197	196	193	195
Temperature (°F)	387	385	380	384
Moisture (%)	5.9	12.0	11.2	9.7
Oxygen, dry (%)	14.2	14.6	13.3	14.0
CO_2, dry (%)	5.8	5.4	6.7	6.0
Particulate Emissions				
g/Nm^3-dry	0.119	0.153	0.149	0.140
g/Nm^3-dry @ 12% CO_2	0.247	0.341	0.264	0.284
gr/dscf	0.052	0.067	0.065	0.061
gr/dscf @ 12% CO_2	0.108	0.149	0.116	0.124
ng/J	96.3	131.6	105.8	111.2
lb/10^6 Btu	0.224	0.306	0.246	0.259
Average Opacity				
Control Device				
Type	NONE			
Operating Parameter[1]				
Design Parameter[1]				
Design Flow Rate (ACFM)				

[1] For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT FD3[98]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	11/6/79	11/7/79	11/7/79	
% Isokinetic	100.3	102.3	101.6	
Boiler Load (% of design)	74	73	80	76
Sample Point Location	West Stack			
Stack Gas Data				
Flow (Nm^3/s-dry)	2.7	3.0	3.0	2.9
Flow (dscfm)	5,690	6,260	6,360	6,100
Temperature (°C)	202	208	212	207
Temperature (°F)	395	406	413	405
Moisture (%)	15.6	13.5	14.0	14.3
Oxygen, dry (%)	11.0	13.2	12.0	12.1
CO_2, dry (%)	7.8	6.2	7.2	7.1
Particulate Emissions				
g/Nm^3-dry	0.238	0.172	0.121	0.177
g/Nm^3-dry @ 12% CO_2	0.366	0.332	0.201	0.300
gr/dscf	0.104	0.075	0.053	0.077
gr/dscf @ 12% CO_2	0.160	0.145	0.088	0.131
ng/J	130.3	120.4	73.5	108.1
lb/10^6 Btu	0.303	0.280	0.171	0.251
Average Opacity	13.3	17.7	16.3	15.8
Control Device				
Type	NONE			
Operating Parameter[1]				
Design Parameter[1]				
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT FE[99]

Boiler No. 1 at Plant FE was tested to determine the particulate emission rate. Boiler No. 1 is an overfeed stoker rated at 110,000 pounds per hour of steam. The boiler is fueled with 100 percent municipal solid waste. Particulate emissions are controlled by an ESP. The design SCA of the ESP is 154 ft^2/1000 ACFM.

Three EPA Method 5 test runs were performed simultaneously at both the inlet and outlet of the ESP. Two additional test runs were run at the outlet of the ESP only. Three of the outlet runs are not presented for reasons discussed below. The average boiler load during testing was 79 percent of rated capacity. The average outlet particulate emission rate for the two good runs was 0.077 pounds per million Btu. The fuel burned during the test had an ash content of 31.2 percent and a moisture content of 26.4 percent. The average SCA during the test was 278 ft^2/1000 ACFM.

The measured emissions at the ESP outlet on Run 1, using EPA Method 5, were much higher than for Runs 2 and 3. Since the measured ESP inlet emissions for this run were significantly lower than Runs 2 and 3 and the SCA was significantly higher, this test run should have resulted in lower emissions than Runs 2 and 3. When the EPA results were compared to data obtained simultaneously using an ASME test method, the ASME test data showed more consistent emissions for all three runs. Therefore the high results obtained during Run 1 using the EPA sampling method are believed to be questionable. Because of this, Run 1 is not presented and was not used in NSPS development.

Two preliminary test runs were also performed at the ESP outlet only. One of these runs was not performed in accordance with proper EPA Method 5 procedures. The other preliminary emission test run at the ESP outlet had an inconsistency in the oxygen content and gas flow rate when compared to the last two test runs. However, the run was consistent with Run 1 oxygen content and flue gas flow. Since the results of Run 1 are believed to be in error, whatever caused the error in Run 1 is also believed to have caused this run to be in error. Therefore, neither of these preliminary outlet test runs are presented here or were used in NSPS development.

PLANT FE1 99

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	5/12/71	5/13/71	5/13/71	
% Isokinetic	92	102	99.6	
Boiler Load (% of design)	78	79	79	79
Sample Point Location	Inlet of ESP			
Stack Gas Data				
Flow (Nm^3/s-dry)	17.5	21.9	19.9	19.8
Flow (dscfm)	37,160	46,450	42,100	41,900
Temperature (°C)	158	170	153	160
Temperature (°F)	317	338	307	321
Moisture (%)	7.77	11.0	10.8	9.9
Oxygen, dry (%)	12.0	9.4	9.4	10.3
CO_2, dry (%)	8.2	10.0	10.0	9.4
Particulate Emissions				
g/Nm^3-dry	1.40	2.68	2.88	2.32
g/Nm^3-dry @ 12% CO_2	2.05	3.20	3.46	2.90
gr/dscf	0.613	1.17	1.26	1.01
gr/dscf @ 12% CO_2	0.897	1.40	1.51	1.27
ng/J	851.4	1,259.9	1,354.5	1,155.3
lb/10^6 Btu	1.98	2.93	3.15	2.69
Average Opacity				
Control Device				
Type	---			
Operating Parameter[1]				
Design Parameter[1]				
Design Flow Rate (ACFM)				

[1] For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT FE299

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date		5/13/71	5/13/71	
% Isokinetic		90	99.9	
Boiler Load (% of design)		79	79	79
Sample Point Location	Outlet of ESP			
Stack Gas Data				
Flow (Nm^3/s-dry)		22.9	20.5	21.7
Flow (dscfm)		48,600	43,400	46,000
Temperature (°C)		181	180	180
Temperature (°F)		358	356	357
Moisture (%)		9.65	8.45	9.0
Oxygen, dry (%)		9.4	9.4	9.4
CO_2, dry (%)		10.0	10.0	10.0
Particulate Emissions				
g/Nm^3-dry		0.076	0.064	0.070
g/Nm^3-dry @ 12% CO_2		0.092	0.078	0.085
gr/dscf		0.033	0.028	0.030
gr/dscf @ 12% CO_2		0.040	0.034	0.037
ng/J		35.6	30.4	33.0
lb/10^6 Btu		0.0828	0.0708	0.077
Average Opacity				
Control Device				
Type	ESP			
Operating Parameter[1]		260	297	278
Design Parameter[1]	154			
Design Flow Rate (ACFM)	143,000			

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

C.1.4 RDF-Fired Boilers

The following facility descriptions and particulate emission data are for RDF-fired boilers. Each site is given a 2-letter plant designation. The first letter, H, indicates the facility has an RDF-fired boiler. The second letter indicates the plant. The number after the plant designation distinguishes between different tests at the same plant.

PLANT HC[100]

Tests at boiler No. 1 at Plant HC were conducted by the EPA and MRI (Midwest Research Institute) to determine the particulate emission rate. Boiler No. 1 burns mixtures of coal and air classified refuse derived fuel (RDF) in a pulverized coal-fired boiler rated at 925,000 pounds per hour of steam. Particulate emissions are controlled by an ESP with a design SCA of 135 ft^2/1000 ACFM.

A total of 10 EPA Method 5 test runs were performed both at the inlet and outlet of the ESP. These test runs are numbered HC1 through HC20. The odd numbered test runs were performed at the ESP inlet and the even test runs at the ESP outlet. The steam production rate during testing ranged from 64 percent to 96 percent of rated capacity. The amount of RDF burned ranged from 0 percent to 27 percent by heat input. The particulate emission rates ranged from 0.054 pounds per million Btu to 0.115 pounds per million Btu. The SCA during the tests ranged from 82 to 142 ft^2/1000 ACFM.

For tests HC1 through HC20, the fuel analyses were as follows:[1]

	Test HC1 & HC2 Coal/RDF Run 1	Test HC3 & HC4 Coal/RDF Run 1	Test HC5 & HC6 Coal/RDF Run 1	Run 2	Test HC7 & HC8 Coal/RDF Run 1
% H_2O	6.35	6.02/23.2	6.51/39.0	6.48/49.0	6.27/37.8
% Ash_d	6.70	7.56/18.5	6.55/12.1	7.87/12.9	6.76/13.3
% S_d	1.35	1.59/0.17	1.56/0.12	1.61/0.09	1.47/0.10
HHV_d(Btu/lb)	13,480	13,330/6,830	13,470/7,400	13,240/7,010	13,440/7,050
HHV_d(kJ/kg)	31,350	31,010/15,890	31,330/17,210	30,800/16,300	31,260/16,400
% RDF	0	9	18	18	27

	Test HC9 & HC10 Coal Run 1	Test HC11 & HC12 Coal/RDF Run 1	Run 2	Run 3	Test HC13 & HC14 Coal/RDF Run 1
% H_2O	6.49	5.96/34.4	6.17/22.3	6.37/34.5	6.28/23.6
% Ash_d	6.54	6.86/13.7	7.57/15.7	7.06/14.9	8.33/17.9
% S_d	1.33	1.46/0.09	1.73/0.12	1.50/0.14	2.80/0.11
HHV_d(Btu/lb)	13,420	13,400/7,320	13,340/7,120	13,440/7,390	13,220/6,950
HHV_d(kJ/kg)	31,220	31,220/17,030	31,030/16,560	31,260/17,190	30,750/16,170
% RDF	0	9	9	9	18

	Test HC15 & HC16 Coal Run 1	Test HC17 & HC18 Coal/RDF Run 1	Test HC19 & HC20 Coal/RDF Run 1
% H_2O	6.60	6.62/22.2	6.28/20.0
% Ash_d	7.13	6.26/17.5	6.78/17.1
% S	1.25	1.36/0.16	1.52/0.11
HHV_d(Btu/lb)	13,410	13,580/7,140	13,490/7,260
HHV_d(kJ/kg)	31,190	31,590/16,610	31,380/16,890
% RDF	0	9	18

PLANT HCl 100

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	12/10/73			
% Isokinetic	101			
Boiler Load (% of design)	64			64
Sample Point Location	Inlet of ESP			
% RDF	0			0
Stack Gas Data				
Flow (Nm^3/s-dry)	119.6			119.6
Flow (dscfm)	253,450			253,450
Temperature (°C)	150			150
Temperature (°F)	302			302
Moisture (%)	6.1			6.1
Oxygen, dry (%)	6.7			6.7
CO_2, dry (%)	13.6			13.6
Particulate Emissions				
g/Nm^3-dry	3.57			3.57
g/Nm^3-dry @ 12% CO_2	3.15			3.15
gr/dscf	1.56			1.56
gr/dscf @ 12% CO_2	1.38			1.38
ng/J	1,380.3			1,380.3
lb/10^6 Btu	3.21			3.21
Average Opacity				
Control Device				
Type				
Operating Parameter[1]				
Design Parameter[1]				
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT HC2 100

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	12/10/73			
% Isokinetic	102			
Boiler Load (% of design)	64			64
Sample Point Location	Outlet of ESP			
% RDF	0	0	0	0
Stack Gas Data				
Flow (Nm^3/s-dry)	110.0			110.0
Flow (dscfm)	233,040			233,040
Temperature (°C)	150			150
Temperature (°F)	302			302
Moisture (%)	6.2			6.2
Oxygen, dry (%)	6.7			6.7
CO_2, dry (%)	13.6			13.6
Particulate Emissions				
g/Nm^3-dry	0.098			0.098
g/Nm^3-dry @ 12% CO_2	0.087			0.087
gr/dscf	0.043			0.043
gr/dscf @ 12% CO_2	0.038			0.038
ng/J	37.8			37.8
lb/10^6 Btu	0.088			0.088
Average Opacity				
Control Device				
Type	ESP			
Operating Parameter[1]				142
Design Parameter[1]	135			
Design Flow Rate (ACFM)	411,500			

[1] For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM. For FF, A/C = ft/min.

PLANT HC3 100

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	12/14			
% Isokinetic	99.4			
Boiler Load (% of design)	64			64
Sample Point Location	Inlet of ESP			
% RDF	9			9
Stack Gas Data				
Flow (Nm^3/s-dry)	118.0			118.0
Flow (dscfm)	250,200			250,200
Temperature (°C)	153			153
Temperature (°F)	307			307
Moisture (%)	7.9			7.9
Oxygen, dry (%)	6.0			6.0
CO_2, dry (%)	15.0			15.0
Particulate Emissions				
g/Nm^3-dry	4.26			4.26
g/Nm^3-dry @ 12% CO_2	3.40			3.40
gr/dscf	1.86			1.86
gr/dscf @ 12% CO_2	1.49			1.49
ng/J	1,565.2			1,565.2
lb/10^6 Btu	3.64			3.64
Average Opacity				
Control Device				
Type				
Operating Parameter[1]				
Design Parameter[1]				
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT HC4 100

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	12/14			
% Isokinetic	100.7			
Boiler Load (% of design)	67			64
Sample Point Location	Outlet of ESP			
% RDF	9			9
Stack Gas Data				
Flow (Nm^3/s-dry)	106.9			106.9
Flow (dscfm)	226,506			226,506
Temperature (°C)	152			152
Temperature (°F)	306			306
Moisture (%)	7.8			7.8
Oxygen, dry (%)	6.0			6.0
CO_2, dry (%)	15.0			15.0
Particulate Emissions				
g/Nm^3-dry	0.092			0.092
g/Nm^3-dry @ 12% CO_2	0.073			0.073
gr/dscf	0.040			0.040
gr/dscf @ 12% CO_2	0.032			0.032
ng/J	33.5			33.5
lb/10^6 Btu	0.078			0.078
Average Opacity				
Control Device				
Type	ESP			
Operating Parameter[1]				139
Design Parameter[1]	135			
Design Flow Rate (ACFM)	411,500			

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT HC5 100

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	12/9/73	12/9/73		
% Isokinetic	100	97		
Boiler Load (% of design)				64
Sample Point Location	Inlet of ESP			
% RDF	18	18		18
Stack Gas Data				
Flow (Nm^3/s-dry)	110.3	125.3		117.8
Flow (dscfm)	233,760	265,600		249,680
Temperature (°C)	158	160		159
Temperature (°F)	317	320		318
Moisture (%)	10.9	10.0		10.5
Oxygen, dry (%)	7.0	6.0		6.5
CO_2, dry (%)	14.5	14.5		14.5
Particulate Emissions				
g/Nm^3-dry	4.51	4.35		4.43
g/Nm^3-dry @ 12% CO_2	3.73	3.60		3.66
gr/dscf	1.97	1.90		1.94
gr/dscf @ 12% CO_2	1.63	1.57		1.60
ng/J	1,772	1,591		1,682
lb/10^6 Btu	4.12	3.70		3.91
Average Opacity				
Control Device				
Type				
Operating Parameter[1]				
Design Parameter[1]				
Design Flow Rate (ACFM)				

[1] For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM. For FF, A/C = ft/min.

PLANT HC6 100

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	12/9/73	12/9/73		
% Isokinetic	100	97		
Boiler Load (% of design)	64	64		64
Sample Point Location	Outlet of ESP			
% RDF	18	18		18
Stack Gas Data				
Flow (Nm^3/s-dry)	104.0	103.6		103.8
Flow (dscfm)	220,410	219,570		219,990
Temperature (°C)	159	158		158
Temperature (°F)	318	316		317
Moisture (%)	8.8	9.0		8.9
Oxygen, dry (%)	7.0	6.0		6.5
CO_2, dry (%)	14.5	14.5		14.5
Particulate Emissions				
g/Nm^3-dry	0.055	0.069		0.062
g/Nm^3-dry @ 12% CO_2	0.045	0.057		0.051
gr/dscf	0.024	0.030		0.027
gr/dscf @ 12% CO_2	0.020	0.025		0.022
ng/J	21.5	24.9		23.2
lb/10^6 Btu	0.050	0.058		0.054
Average Opacity				
Control Device				
Type	ESP			
Operating Parameter[1]				134
Design Parameter[1]	135			
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT HC7 100

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	12/10/73			
% Isokinetic	105			
Boiler Load (% of design)	64			64
Sample Point Location	Inlet of ESP			
% RDF	27			27
Stack Gas Data				
Flow (Nm^3/s-dry)	115.0			115.0
Flow (dscfm)	243,570			243,570
Temperature (°C)	152			152
Temperature (°F)	306			306
Moisture (%)	10.8			10.8
Oxygen, dry (%)	5.6			5.6
CO_2, dry (%)	14.7			14.7
Particulate Emissions				
g/Nm^3-dry	4.76			4.76
g/Nm^3-dry @ 12% CO_2	3.88			3.88
gr/dscf	2.08			2.08
gr/dscf @ 12% CO_2	1.70			1.70
ng/J	1,694			1,694
lb/10^6 Btu	3.94			3.94
Average Opacity				
Control Device				
Type				
Operating Parameter[1]				
Design Parameter[1]				
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT HC8 100

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	12/10/73			
% Isokinetic	106			
Boiler Load (% of design)	64			64
Sample Point Location	Outlet of ESP			
% RDF	27			27
Stack Gas Data				
Flow (Nm^3/s-dry)	104.6			104.6
Flow (dscfm)	221,720			221,720
Temperature (°C)	152			152
Temperature (°F)	305			305
Moisture (%)	8.2			8.2
Oxygen, dry (%)	5.6			5.6
CO_2, dry (%)	14.7			14.7
Particulate Emissions				
g/Nm^3-dry	0.073			0.073
g/Nm^3-dry @ 12% CO_2	0.060			0.060
gr/dscf	0.032			0.032
gr/dscf @ 12% CO_2	0.026			0.026
ng/J	26.2			26.2
lb/10^6 Btu	0.061			0.061
Average Opacity				
Control Device				
Type	ESP			
Operating Parameter[1]				140
Design Parameter[1]	135			
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT HC9 100

TEST SUMMARY SHEETS
(Particulates only)

Test Number	One	Two	Three	Average
General Data				
Date	12/6/73			
% Isokinetic	97.7			
Boiler Load (% of design)	80			80
Sample Point Location	Inlet			
% RDF	0			0
Stack Gas Data				
Flow (Nm^3/s-dry)	155.0			155.0
Flow (dscfm)	309,900			309,900
Temperature (°C)	154			154
Temperature (°F)	309			309
Moisture (%)	7.5			7.5
Oxygen, dry (%)	6.6			6.6
CO_2, dry (%)	13.6			13.6
Particulate Emissions				
g/Nm^3-dry	4.12			4.12
g/Nm^3-dry @ 12% CO_2	3.63			3.63
gr/dscf	1.80			1.80
gr/dscf @ 12% CO_2	1.59			1.59
ng/J	1,582			1,582
lb/10^6 Btu	3.68			3.68
Average Opacity				
Control Device				
Type				
Operating Parameter[1]				
Design Parameter[1]				
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT HC10 100

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	12/6/73			
% Isokinetic	101.3			
Boiler Load (% of design)	80			80
Sample Point Location	Outlet of ESP			
% RDF	0			0
Stack Gas Data				
Flow (Nm^3/s-dry)	125.2			125.2
Flow (dscfm)	265,330			265,330
Temperature (°C)	157			157
Temperature (°F)	314			314
Moisture (%)	7.3			7.3
Oxygen, dry (%)	6.6			6.6
CO_2, dry (%)	13.6			13.6
Particulate Emissions				
g/Nm^3-dry	0.114			0.114
g/Nm^3-dry @ 12% CO_2	0.101			0.101
gr/dscf	0.050			0.050
gr/dscf @ 12% CO_2	0.044			0.044
ng/J	43.9			43.9
lb/10^6 Btu	0.102			0.102
Average Opacity				
Control Device				
Type	ESP			
Operating Parameter[1]				140
Design Parameter[1]	135			
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT HC11 [100]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	12/13/73	12/5/73	12/5/73	
% Isokinetic	99.1	98	101	
Boiler Load (% of design)				80
Sample Point Location	Inlet of ESP			
% RDF	9	9	9	9
Stack Gas Data				
Flow (Nm^3/s-dry)	138.5	149.9	137.4	141.8
Flow (dscfm)	293,520	317,530	291,030	300,690
Temperature (°C)	156	158	157	157
Temperature (°F)	312	316	314	314
Moisture (%)	8.9	9.0	10.6	9.5
Oxygen, dry (%)	5.9	6.0	5.5	5.8
CO_2, dry (%)	15.2	14.5	14.5	14.7
Particulate Emissions				
g/Nm^3-dry	4.16	4.46	4.21	4.28
g/Nm^3-dry @ 12% CO_2	3.29	3.69	3.48	3.49
gr/dscf	1.82	1.95	1.84	1.87
gr/dscf @ 12% CO_2	1.44	1.61	1.52	1.52
ng/J	1,518	1,638	1,496	1,551
lb/10^6 Btu	3.53	3.81	3.48	3.61
Average Opacity				
Control Device				
Type				
Operating Parameter[1]				
Design Parameter[1]				
Design Flow Rate (ACFM)				

[1] For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT HC12 100

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	12/13/73	12/5/73	12/5/73	
% Isokinetic	99.1	99.5	104	
Boiler Load (% of design)	80	80	80	80
Sample Point Location	Outlet of ESP			
% RDF	9	9	9	9
Stack Gas Data				
Flow (Nm^3/s-dry)	127.2	121.9	119.9	122.7
Flow (dscfm)	269,620	258,310	254,090	260,670
Temperature (°C)	159	153	157	156
Temperature (°F)	318	308	314	313
Moisture (%)	8.0	9.3	10.0	9.1
Oxygen, dry (%)	5.9	6.0	5.5	5.8
CO_2, dry (%)	15.2	14.5	14.5	14.7
Particulate Emissions				
g/Nm^3-dry	0.112	0.128	0.169	0.136
g/Nm^3-dry @ 12% CO_2	0.008	0.106	0.140	0.111
gr/dscf	0.049	0.056	0.074	0.060
gr/dscf @ 12% CO_2	0.039	0.046	0.061	0.049
ng/J	40.8	46.9	60.2	49.3
lb/10^6 Btu	0.095	0.109	0.140	0.115
Average Opacity				
Control Device				
Type	ESP			
Operating Parameter[1]				113
Design Parameter[1]	135			
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT HC13 100

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	12/13/73			
% Isokinetic	100.2			
Boiler Load (% of design)	80			80
Sample Point Location	Inlet of ESP			
% RDF	18			18
Stack Gas Data				
Flow (Nm^3/s-dry)	134.7			134.7
Flow (dscfm)	285,350			285,350
Temperature (°C)	159			159
Temperature (°F)	318			318
Moisture (%)	10.0			10.0
Oxygen, dry (%)	6.0			6.0
CO_2, dry (%)	13.3			13.3
Particulate Emissions				
g/Nm^3-dry	4.69			4.69
g/Nm^3-dry @ 12% CO_2	4.23			4.23
gr/dscf	2.05			2.05
gr/dscf @ 12% CO_2	1.85			1.85
ng/J	1,720			1,720
lb/10^6 Btu	4.00			4.00
Average Opacity				
Control Device				
Type				
Operating Parameter[1]				
Design Parameter[1]				
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM. For FF, A/C = ft/min.

PLANT HC14 100

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	12/13/73			
% Isokinetic	100.2			
Boiler Load (% of design)	80			80
Sample Point Location	Outlet of ESP			
% RDF	18			18
Stack Gas Data				
Flow (Nm^3/s-dry)	120.0			120.0
Flow (dscfm)	254,220			254,220
Temperature (°C)	159			159
Temperature (°F)	318			318
Moisture (%)	8.5			8.5
Oxygen, dry (%)	6.0			6.0
CO_2, dry (%)	13.3			13.3
Particulate Emissions				
g/Nm^3-dry	0.146			0.146
g/Nm^3-dry @ 12% CO_2	0.132			0.132
gr/dscf	0.064			0.064
gr/dscf @ 12% CO_2	0.058			0.058
ng/J	53.8			53.8
lb/10^6 Btu	0.125			0.125
Average Opacity				
Control Device				
Type	ESP			
Operating Parameter[1]				110
Design Parameter[1]	135			
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT HC15 100

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	12/13/73			
% Isokinetic	96.8			
Boiler Load (% of design)	96			96
Sample Point Location	Inlet of ESP			
% RDF	0			0
Stack Gas Data				
Flow (Nm^3/s-dry)	163.9			163.9
Flow (dscfm)	347,400			347,400
Temperature (°C)	153			153
Temperature (°F)	308			308
Moisture (%)	7.7			7.7
Oxygen, dry (%)	5.7			5.7
CO_2, dry (%)	14.6			14.6
Particulate Emissions				
g/Nm^3-dry	4.39			4.39
g/Nm^3-dry @ 12% CO_2	3.61			3.61
gr/dscf	1.92			1.92
gr/dscf @ 12% CO_2	1.58			1.58
ng/J	1,600			1,600
lb/10^6 Btu	3.72			3.72
Average Opacity				
Control Device				
Type				
Operating Parameter[1]				
Design Parameter[1]				
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT HC16 100

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	12/12/73			
% Isokinetic	95			
Boiler Load (% of design)	96			96
Sample Point Location	Outlet of ESP			
% RDF	0			0
Stack Gas Data				
Flow (Nm^3/s-dry)	142.0			142.0
Flow (dscfm)	300,850			300,850
Temperature (°C)	151			151
Temperature (°F)	304			304
Moisture (%)	6.9			6.9
Oxygen, dry (%)	5.7			5.7
CO_2, dry (%)	14.6			14.6
Particulate Emissions				
g/Nm^3-dry	0.153			0.153
g/Nm^3-dry @ 12% CO_2	0.126			0.126
gr/dscf	0.067			0.067
gr/dscf @ 12% CO_2	0.055			0.055
ng/J	55.9			55.9
lb/10^6 Btu	0.130			0.130
Average Opacity				
Control Device				
Type	ESP			
Operating Parameter[1]				92
Design Parameter[1]	135			
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT HC17 100

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	12/11/73			
% Isokinetic	95.5			
Boiler Load (% of design)	96			96
Sample Point Location	Inlet of ESP			
% RDF	9			9
Stack Gas Data				
Flow (Nm^3/s-dry)	195.0			195.0
Flow (dscfm)	413,130			413,130
Temperature (°C)	155			155
Temperature (°F)	311			311
Moisture (%)	9.0			9.0
Oxygen, dry (%)	5.8			5.8
CO_2, dry (%)	13.5			13.5
Particulate Emissions				
g/Nm^3-dry	4.12			4.12
g/Nm^3-dry @ 12% CO_2	3.66			3.66
gr/dscf	1.80			1.80
gr/dscf @ 12% CO_2	1.60			1.60
ng/J	1,492			1,492
lb/10^6 Btu	3.47			3.47
Average Opacity				
Control Device				
Type				
Operating Parameter[1]				
Design Parameter[1]				
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM. For FF, A/C = ft/min.

PLANT HC18 100

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	12/11/73			
% Isokinetic	99.0			
Boiler Load (% of design)	96			96
Sample Point Location	Outlet of ESP			
% RDF	9			9
Stack Gas Data				
Flow (Nm^3/s-dry)	144.8			144.8
Flow (dscfm)	306,680			306,680
Temperature (°C)	156			156
Temperature (°F)	312			312
Moisture (%)	8.0			8.0
Oxygen, dry (%)	5.8			5.8
CO_2, dry (%)	13.5			13.5
Particulate Emissions				
g/Nm^3-dry	0.100			0.100
g/Nm^3-dry @ 12% CO_2	0.090			0.090
gr/dscf	0.044			0.044
gr/dscf @ 12% CO_2	0.039			0.039
ng/J	36.6			36.6
lb/10^6 Btu	0.085			0.085
Average Opacity				
Control Device				
Type	ESP			
Operating Parameter[1]				82
Design Parameter[1]	135			
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT HC19 100

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	12/12/73			
% Isokinetic	97.4			
Boiler Load (% of design)	96			96
Sample Point Location	Inlet of ESP			
% RDF	18			18
Stack Gas Data				
Flow (Nm^3/s-dry)	163.5			163.5
Flow (dscfm)	346,570			346,570
Temperature (°C)	151			151
Temperature (°F)	303			303
Moisture (%)	9.3			9.3
Oxygen, dry (%)	5.3			5.3
CO_2, dry (%)	15.6			15.6
Particulate Emissions				
g/Nm^3-dry	3.68			3.68
g/Nm^3-dry @ 12% CO_2	2.83			2.83
gr/dscf	1.61			1.61
gr/dscf @ 12% CO_2	1.24			1.24
ng/J	1,290			1,290
lb/10^6 Btu	3.00			3.00
Average Opacity				
Control Device				
Type				
Operating Parameter[1]				
Design Parameter[1]				
Design Flow Rate (ACFM)				

[1] For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM. For FF, A/C = ft/min.

PLANT HC20 100

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	12/12/73			
% Isokinetic	98.4			
Boiler Load (% of design)	96			96
Sample Point Location	Outlet of ESP			
% RDF	18			18
Stack Gas Data				
Flow (Nm^3/s-dry)	137.1			137.1
Flow (dscfm)	290,550			290,550
Temperature (°C)	152			152
Temperature (°F)	306			306
Moisture (%)	8.4			8.4
Oxygen, dry (%)	5.3			5.3
CO_2, dry (%)	15.6			15.6
Particulate Emissions				
g/Nm^3-dry	0.142			0.142
g/Nm^3-dry @ 12% CO_2	0.109			0.109
gr/dscf	0.062			0.062
gr/dscf @ 12% CO_2	0.048			0.048
ng/J	49.4			49.4
lb/10^6 Btu	0.115			0.115
Average Opacity				
Control Device				
Type	ESP			
Operating Parameter[1]				97
Design Parameter[1]	135			
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT HD[101]

Boiler #1 at Plant HD was tested to determine the particulate emission rate. Boiler No. 1 is a spreader stoker cofired with coal and pelletized RDF. The boiler rated capacity is 45,000 pounds per hour of steam. Particulate emissions are controlled by a mechanical collector.

Five EPA Method 5 test runs were performed at four levels of RDF usage ranging from 26 percent to 100 percent. One test run is not presented due to incomplete data. The boiler load ranged from 31 percent to 56 percent of rated capacity. The particulate emission rate ranged from 0.43 to 1.0 pounds per million Btu.

For tests HD1, HD2, and HD3, the fuel analyses were as follows:[1,2]

	Test HD1		Test HD2	Test HD3
	Run 1	Run 2	Run 1	Run 1
%H_2O	5.37	5.44	5.10	5.93
%Ash_d	11.57	11.90	15.12	14.16
%S_d	0.98	0.86	0.63	0.35
%N_d	1.15	1.00	1.07	0.72
HHV_d(Btu/lb)	11,169	10,785	10,433	8,649
HHV_d(kJ/kg)	25,980	25,090	24,270	20,120
% RDF	28	24	53	100

[1]Subscript 'd' designates dry basis.
[2]The fuel analyses are combined averages of coal and RDF.

PLANT HDI101

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	8/10/76	8/11/76		
% Isokinetic	103	109		
Boiler Load (% of design)	59	52		56
Sample Point Location	Outlet of MC			
% RDF	28	24		26
Stack Gas Data				
Flow (Nm^3/s-dry)	4.6	4.0		4.3
Flow (dscfm)	9,830	8,530		9,180
Temperature (°C)	250	243		247
Temperature (°F)	482	470		476
Moisture (%)	6.5	6.3		6.4
Oxygen, dry (%)	5.0	5.5		5.2
CO_2, dry (%)	12.4	12.6		12.5
Particulate Emissions				
g/Nm^3-dry	1.711	0.643		1.177
g/Nm^3-dry @ 12% CO_2	1.656	0.613		1.134
gr/dscf	0.748	0.281		0.514
gr/dscf @ 12% CO_2	0.724	0.268		0.496
ng/J	584.8	227.5		406.1
lb/10^6 Btu	1.36	0.529		0.945
Average Opacity				
Control Device				
Type	MC			
Operating Parameter[1]				
Design Parameter[1]				
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT HD2 101

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	8/10/76			
% Isokinetic	107			
Boiler Load (% of design)	54			54
Sample Point Location	Outlet of MC			
% RDF	53			53
Stack Gas Data				
Flow (Nm^3/s-dry)	4.9			4.9
Flow (dscfm)	10,380			10,380
Temperature (°C)	250			250
Temperature (°F)	482			482
Moisture (%)	7.2			7.2
Oxygen, dry (%)	6.0			6.0
CO_2, dry (%)	11.6			11.6
Particulate Emissions				
g/Nm^3-dry	0.972			0.972
g/Nm^3-dry @ 12% CO_2	1.007			1.007
gr/dscf	0.425			0.425
gr/dscf @ 12% CO_2	0.440			0.440
ng/J	352.6			352.6
lb/10^6 Btu	0.82			0.82
Average Opacity				
Control Device				
Type	MC			
Operating Parameter[1]				
Design Parameter[1]				
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT HD3 101

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	8/10/76			
% Isokinetic	107			
Boiler Load (% of design)	31			31
Sample Point Location	Outlet of MC			
% RDF	100			100
Stack Gas Data				
Flow (Nm^3/s-dry)	4.3			4.3
Flow (dscfm)	9,220			9,220
Temperature (°C)	227			227
Temperature (°F)	441			441
Moisture (%)	4.5			4.5
Oxygen, dry (%)	7.4			7.4
CO_2, dry (%)	10.0			10.0
Particulate Emissions				
g/Nm^3-dry	0.439			0.439
g/Nm^3-dry @ 12% CO_2	0.526			0.526
gr/dscf	0.192			0.192
gr/dscf @ 12% CO_2	0.230			0.230
ng/J	173.3			173.3
lb/10^6 Btu	0.403			0.403
Average Opacity				
Control Device				
Type	MC			
Operating Parameter[1]				
Design Parameter[1]				
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT HE[102]

Boiler No. 3 at Plant HE was tested to determine the particulate emission rate. Boiler No. 3 is a spreader stoker rated at 35,000 pounds per hour of steam. It burns coal and pelletized RDF. Particulate emissions are controlled with a mechanical collector.

Four EPA Method 5 tests were run at four levels of RDF ranging from 0 percent to 40 percent (heat input basis). The particulate emission rate ranged from 0.494 to 1.22 pounds per million Btu. The RDF had an average composition of 6.36 percent moisture, 28.54 percent ash and a heating value of 6068 Btu/lb.

For tests HE1, HE2, HE3, and HE4, the fuel analyses were as follows:[1,2]

	Test HE1	Test HE2	Test HE3	Test HE4
% H_2O	24.89	18.40	17.42	11.86
% Ash_d	9.97	14.85	16.42	23.64
% S_d	0.93	0.80	0.92	0.57
% N_d	0.96	0.94	0.92	0.88
HHV_d(Btu/lb)	11,948	10,482	10,023	8,237
HHV_d(kJ/kg)	27,790	24,380	23,300	19,160
% RDF	0	20	30	40

[1]Subscript 'd' designates dry basis.
[2]The fuel analyses are combined averages of coal and RDF.

PLANT HE1

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	6/4/76			
% Isokinetic	100			
Boiler Load (% of design)	58			58
Sample Point Location	Outlet of MC			
% RDF	0			0
Stack Gas Data				
Flow (Nm^3/s-dry)	7.3			7.3
Flow (dscfm)	15,400			15,400
Temperature (°C)	268			268
Temperature (°F)	515			515
Moisture (%)	5.1			5.1
Oxygen, dry (%)	9.7			9.7
CO_2, dry (%)	9.5			9.5
Particulate Emissions				
g/Nm^3-dry	0.496			0.496
g/Nm^3-dry @ 12% CO_2	0.627			0.627
gr/dscf	0.217			0.217
gr/dscf @ 12% CO_2	0.274			0.274
ng/J	243.4			243.4
lb/10^6 Btu	0.566			0.566
Average Opacity				
Control Device				
Type	MC			
Operating Parameter[1]				
Design Parameter[1]				
Design Flow Rate (ACFM)				

[1] For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM. For FF, A/C = ft/min.

PLANT HE2 102

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	6/3/76			
% Isokinetic	105			
Boiler Load (% of design)	61			61
Sample Point Location	Outlet of MC			
% RDF	20			20
Stack Gas Data				
Flow (Nm^3/s-dry)	7.2			7.2
Flow (dscfm)	15,200			15,200
Temperature (°C)	273			273
Temperature (°F)	524			524
Moisture (%)	7.9			7.9
Oxygen, dry (%)	9.6			9.6
CO_2, dry (%)	9.5			9.5
Particulate Emissions				
g/Nm^3-dry	0.616			0.616
g/Nm^3-dry @ 12% CO_2	0.778			0.778
gr/dscf	0.269			0.269
gr/dscf @ 12% CO_2	0.340			0.340
ng/J	297			297
lb/10^6 Btu	0.691			0.691
Average Opacity				
Control Device				
Type	MC			
Operating Parameter[1]				
Design Parameter[1]				
Design Flow Rate (ACFM)				

[1] For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT HE3 102

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	6/4/76			
% Isokinetic	96			
Boiler Load (% of design)	52			52
Sample Point Location	Outlet of MC			
% RDF	30			30
Stack Gas Data				
Flow (Nm^3/s-dry)	5.8			5.8
Flow (dscfm)	12,250			12,250
Temperature (°C)	259			259
Temperature (°F)	498			498
Moisture (%)	9.9			9.9
Oxygen, dry (%)	11.5			11.5
CO_2, dry (%)	8.3			8.3
Particulate Emissions				
g/Nm^3-dry	0.366			0.366
g/Nm^3-dry @ 12% CO_2	0.531			0.531
gr/dscf	0.160			0.160
gr/dscf @ 12% CO_2	0.232			0.232
ng/J	212.4			212.4
$lb/10^6$ Btu	0.494			0.494
Average Opacity				
Control Device				
Type	MC			
Operating Parameter[1]				
Design Parameter[1]				
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT HE4 102

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	6/3/76			
% Isokinetic	102			
Boiler Load (% of design)	61			61
Sample Point Location	Outlet of MC			
% RDF	40			40
Stack Gas Data				
Flow (Nm^3/s-dry)	6.6			6.6
Flow (dscfm)	13,900			13,900
Temperature (°C)	274			274
Temperature (°F)	525			525
Moisture (%)	10.3			10.3
Oxygen, dry (%)	10.5			10.5
CO_2, dry (%)	8.9			8.9
Particulate Emissions				
g/Nm^3-dry	1.009			1.009
g/Nm^3-dry @ 12% CO_2	1.361			1.361
gr/dscf	0.441			0.441
gr/dscf @ 12% CO_2	0.595			0.595
ng/J	524.6			524.6
lb/10^6 Btu	1.22			1.22
Average Opacity				
Control Device				
Type	MC			
Operating Parameter[1]				
Design Parameter[1]				
Design Flow Rate (ACFM)				

[1] For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM. For FF, A/C = ft/min.

PLANT HF[103-105]

Boiler No.1 at Plant HF was tested to determine compliance with the state of New York emission standards. Boiler No.1 is a RDF-fired spreader stoker rated at 200,000 pounds per hour of steam. Particulate emissions are controlled by a bank of 12 cyclones followed by an electrostatic precipitator. The ESP has 49,600 ft^2 of collection area and is sized for a gas flow rate of 200,000 ACFM.

The boiler fuel is RDF produced by a wet pulping process. This fuel provided 100 percent of the heat input during testing. The fuel was not analyzed during testing. However, analyses of fuel samples collected monthly showed the following average composition:[1]

% H_2O - 50-52

% Ash_d - 16.2

% S_d - 0.97

% N_d - 0.66

% HHV_d (Btu/lb) - 8138

% HHV_d (kJ/kg) - 18,930

Three EPA Method 5 particulate test runs were performed. The average boiler load during testing was 80.4 percent. The average particulate emission rate for the three runs was 0.066 pounds per million Btu.

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[1]Subscript 'd' designates dry basis.

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	4/30/79	5/1/79	5/1/79	
% Isokinetic	102.7	107.6	96.6	
Boiler Load (% of design)	91.5	77.2	72.4	80.4
Sample Point Location	ESP Outlet			
Stack Gas Data				
Flow (Nm^3/s-dry)	37.6	33.1	32.6	34.4
Flow (dscfm)	79,600	70,200	69,000	72,900
Temperature (°C)	202	198	196	199
Temperature (°F)	396	388	384	389
Moisture (%)	25.3	22.6	23.4	23.7
Oxygen, dry (%)	5.2	9.1	9.1	7.8
CO_2, dry (%)	10.5	8.5	8.4	9.1
Particulate Emissions				
g/Nm^3-dry	0.125	0.038	0.056	0.073
g/Nm^3-dry @ 12% CO_2	0.143	0.054	0.080	0.092
gr/dscf	0.0548	0.0168	0.0244	0.0320
gr/dscf @ 12% CO_2	0.0626	0.0237	0.0349	0.0404
ng/J	42.6	17.2	25.4	28.4
lb/10^6 Btu	0.099	0.040	0.059	0.066
Average Opacity				
Control Device				
Type	ESP			
Operating Parameter[1]	288	343	347	326
Design Parameter[1]	248			
Design Flow Rate (ACFM)	200,000			

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT HG[106,107]

Plant HG was tested as part of an experimental program to determine the effects of cofiring densified RDF and coal in a boiler originally designed to fire coal alone. The boiler is a traveling grate spreader stoker rated at 150,000 pounds per hour of steam. The particulate emissions are controlled by a multiclone followed by an ESP. Flyash collected by the multiclone is reinjected into the boiler. The ESP was designed for a gas flow of 133,000 acfm and has 25,056 ft^2 of collection area.

The test data shown is the emission rate after the ESP. The test runs have been grouped into four sets (HG1 - HG4).

Test HG1 consisted of 4 Method 5 runs while firing 100 percent coal. The average load factor was 95 percent. Particulate emissions were extremely variable, and averaged 0.51 pounds per million Btu. The average SCA for the ESP was 184 ft^2/1000 acfm.

During Test HG2 densified RDF was cofired with the same type of coal fired in test HG1 at an average load factor of 84 percent. There were three Method 5 runs in this test. The percentage of RDF was 25-26 percent (heat input basis). Particulate emissions were again variable but averaged 0.52 pounds per million Btu. The average SCA for the ESP was 186 ft^2/1000 acfm.

During Test HG3 the boiler fired coal with a lower ash and sulfur content than the coal fired in tests HG1 and HG2. A total of six Method 5 runs were performed. Particulate emissions were not as variable during this test and averaged 0.15 pounds per million Btu.

Test HG4 consisted of fourteen Method 5 runs. Densified RDF was cofired with the same type of coal fired in test HG3. The RDF was from a different source and had a lower ash and sulfur content than the RDF fired in Test HG2. The percentage of RDF varied from 23 to 51 percent of the fuel heat input. Particulate emissions were again extremely variable but averaged 0.16 pounds per million Btu. The average load factor during testing was 91 percent and the average SCA was 192 ft^2/1000 acfm.

The average compositions of the fuels fired during testing were:[1]

	Tests HG1 & HG2	Tests HG3 & HG4
	Coal/RDF	Coal/RDF
% H_2O	8.0/21.7	5.4/32.8
% Ash_d	16.9/30.7	10.8/13.8
% S_d	5.46/0.43	1.98/0.23
% N_d	1.04/0.59	1.24/0.37
HHV_d (Btu/lb)	12,098/6,755	12,866/8,123
HHV_d (kJ/kg)	28,140/15,712	29,926/18,894

[1]Subscript 'd' denotes dry basis.

PLANT HG1[106,107]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	3/8/79	3/8/79	3/9/79	
% Isokinetic	___	___	___	
Boiler Load (% of design)	96	95	94	___
Sample Point Location	Outlet of ESP			
Stack Gas Data				
Flow (Nm^3/s-dry)	38.6	38.6	36.9	___
Flow (dscfm)	81,799	81,765	78,103	___
Temperature (°C)	209	209	211	___
Temperature (°F)	408	409	412	___
Moisture (%)	4.2	4.7	4.8	___
Oxygen, dry (%)	8.5	9.0	9.1	___
CO_2, dry (%)	8.9	8.1	8.9	___
Particulate Emissions				
g/Nm^3-dry	0.650	0.270	0.448	___
g/Nm^3-dry @ 12% CO_2	0.876	0.400	0.604	___
gr/dscf	0.284	0.118	0.196	___
gr/dscf @ 12% CO_2	0.383	0.175	0.264	___
ng/J	301	133	219	___
lb/10^6 Btu	0.70	0.31	0.51	___
Average Opacity	___	___	___	___
Control Device				
Type	MC/ESP			
Operating Parameter[1]	181	181	192	___
Design Parameter[1]	188			
Design Flow Rate (ACFM)	133,000			

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT HG1 [106,107]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	3/9/79			
% Isokinetic				
Boiler Load (% of design)	96			95
Sample Point Location	Outlet of ESP			
Stack Gas Data				
Flow (Nm^3/s-dry)	39.0			38.3
Flow (dscfm)	82,645			81,078
Temperature (°C)	217			212
Temperature (°F)	422			413
Moisture (%)	3.3			4.2
Oxygen, dry (%)	9.8			9.1
CO_2, dry (%)	8.9			8.7
Particulate Emissions				
g/Nm^3-dry	0.432			0.451
g/Nm^3-dry @ 12% CO_2	0.583			0.622
gr/dscf	0.189			0.197
gr/dscf @ 12% CO_2	0.255			0.272
ng/J	224			219
lb/10^6 Btu	0.52			0.51
Average Opacity				
Control Device				
Type	MC/ESP			
Operating Parameter[1]	180			184
Design Parameter[1]	188			
Design Flow Rate (ACFM)	133,000			

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT HG2 [106,107]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	3/15/79	3/16/79	3/16/79	
% Isokinetic				
Boiler Load (% of design)	89	81	82	84
Sample Point Location	Outlet of ESP			
% RDF	26	25	25	25
Stack Gas Data				
Flow (Nm^3/s-dry)	37.4	35.6	38.5	37.2
Flow (dscfm)	79,235	75,509	81,490	78,745
Temperature (°C)	192	194	196	194
Temperature (°F)	377	381	384	381
Moisture (%)	1.7	6.1	5.7	4.5
Oxygen, dry (%)	10.7	11.0	10.9	10.9
CO_2, dry (%)	8.0	7.8	7.8	7.9
Particulate Emissions				
g/Nm^3-dry	0.108	0.414	0.616	0.380
g/Nm^3-dry @ 12% CO_2	0.160	0.636	0.947	0.577
gr/dscf	0.047	0.181	0.269	0.166
gr/dscf @ 12% CO_2	0.070	0.278	0.414	0.252
ng/J	60.2	245	361	224
lb/10^6 Btu	0.14	0.57	0.84	0.52
Average Opacity				
Control Device				
Type	MC/ESP			
Operating Parameter[1]	182	194	182	186
Design Parameter[1]	188			
Design Flow Rate (ACFM)	133,000			

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT HG3 [106,107]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	5/16/79	5/16/79	5/17/79	
% Isokinetic				
Boiler Load (% of design)	92	96	93	
Sample Point Location	Outlet of ESP			
Stack Gas Data				
Flow (Nm^3/s-dry)	44.8	44.6	37.2	
Flow (dscfm)	94,944	94,488	78,843	
Temperature (°C)	207	201	206	
Temperature (°F)	405	394	403	
Moisture (%)	3.7	4.0	4.8	
Oxygen, dry (%)	11.1	11.2	10.5	
CO_2, dry (%)	8.4	8.5	8.9	
Particulate Emissions				
g/Nm^3-dry	0.130	0.133	0.108	
g/Nm^3-dry @ 12% CO_2	0.185	0.188	0.144	
gr/dscf	0.057	0.058	0.047	
gr/dscf @ 12% CO_2	0.081	0.082	0.063	
ng/J	73.1	77.4	60.2	
lb/10^6 Btu	0.17	0.18	0.14	
Average Opacity				
Control Device				
Type	MC/ESP			
Operating Parameter[1]	158	161	182	
Design Parameter[1]	188			
Design Flow Rate (ACFM)	133,000			

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT HG3 [106,107]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	5/17/79	5/18/79	5/18/79	
% Isokinetic				
Boiler Load (% of design)	96	96	94	94
Sample Point Location	Outlet of ESP			
Stack Gas Data				
Flow (Nm^3/s-dry)	38.5	36.3	37.6	39.8
Flow (dscfm)	81,472	76,862	79,632	84,374
Temperature (°C)	206	198	206	204
Temperature (°F)	403	389	402	399
Moisture (%)	4.7	5.2	5.1	4.9
Oxygen, dry (%)	10.4	9.7	10.5	10.6
CO_2, dry (%)	8.9	8.9	8.9	8.8
Particulate Emissions				
g/Nm^3-dry	0.119	0.117	0.098	0.119
g/Nm^3-dry @ 12% CO_2	0.160	0.158	0.133	0.162
gr/dscf	0.052	0.051	0.043	0.052
gr/dscf @ 12% CO_2	0.070	0.069	0.058	0.071
ng/J	64.5	60.2	55.9	64.5
lb/10^6 Btu	0.15	0.14	0.13	0.15
Average Opacity				
Control Device				
Type	MC/ESP			
Operating Parameter[1]	181	191	185	176
Design Parameter[1]	188			
Design Flow Rate (ACFM)	133,000			

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT HG4 [106,107]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	4/19/79	4/19/79	4/20/79	
% Isokinetic				
Boiler Load (% of design)	87	84	80	
Sample Point Location	Outlet of ESP			
% RDF	34	34	34	
Stack Gas Data				
Flow (Nm^3/s-dry)	35.5	32.5	35.1	
Flow (dscfm)	75,269	68,920	74,433	
Temperature (°C)	209	216	207	
Temperature (°F)	409	420	404	
Moisture (%)	5.8	7.2	7.9	
Oxygen, dry (%)	9.9	9.7	11.0	
CO_2, dry (%)	9.1	9.3	8.6	
Particulate Emissions				
g/Nm^3-dry	0.032	0.021	0.028	
g/Nm^3-dry @ 12% CO_2	0.041	0.028	0.039	
gr/dscf	0.014	0.009	0.012	
gr/dscf @ 12% CO_2	0.018	0.012	0.017	
ng/J	17.2	12.2	17.2	
lb/10^6 Btu	0.04	0.03	0.04	
Average Opacity				
Control Device				
Type	MC/ESP			
Operating Parameter[1]	197	191	205	
Design Parameter[1]				
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT HG4[106,107]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	4/20/79	4/24/79	4/24/79	
% Isokinetic				
Boiler Load (% of design)	91	80	96	
Sample Point Location	Outlet of ESP			
% RDF	31	36	32	
Stack Gas Data				
Flow (Nm^3/s-dry)	36.8	36.0	38.0	
Flow (dscfm)	77,988	76,283	80,519	
Temperature (°C)	200	199	204	
Temperature (°F)	392	390	399	
Moisture (%)	7.2	7.5	7.4	
Oxygen, dry (%)	10.1	10.6	10.3	
CO_2, dry (%)	9.2	9.0	9.2	
Particulate Emissions				
g/Nm^3-dry	0.037	0.023	0.021	
g/Nm^3-dry @ 12% CO_2	0.048	0.030	0.028	
gr/dscf	0.016	0.010	0.009	
gr/dscf @ 12% CO_2	0.021	0.013	0.012	
ng/J	17.2	12.9	12.9	
lb/10^6 Btu	0.04	0.03	0.03	
Average Opacity				
Control Device				
Type	MC/ESP			
Operating Parameter[1]	193	202	197	
Design Parameter[1]	188			
Design Flow Rate (ACFM)				

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT HG4 [106,107]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	4/25/79	5/8/79	5/8/79	
% Isokinetic				
Boiler Load (% of design)	83	95	100	
Sample Point Location	Outlet of ESP			
% RDF	32	37	35	
Stack Gas Data				
Flow (Nm^3/s-dry)	35.6	39.1	39.2	
Flow (dscfm)	75,515	82,923	83,031	
Temperature (°C)	189	191	191	
Temperature (°F)	373	376	376	
Moisture (%)	8.2	6.4	6.9	
Oxygen, dry (%)	9.5	11.2	10.2	
CO_2, dry (%)	9.2	8.4	9.3	
Particulate Emissions				
g/Nm^3-dry	0.032	0.167	0.076	
g/Nm^3-dry @ 12% CO_2	0.041	0.238	0.098	
gr/dscf	0.014	0.073	0.033	
gr/dscf @ 12% CO_2	0.018	0.104	0.043	
ng/J	17.2	98.9	38.7	
lb/10^6 Btu	0.04	0.23	0.09	
Average Opacity				
Control Device				
Type	MC/ESP			
Operating Parameter[1]	207	176	181	
Design Parameter[1]	188			
Design Flow Rate (ACFM)	133,000			

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT HG4 [106,107]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	5/9/79	5/10/79	5/10/79	
% Isokinetic				
Boiler Load (% of design)	104	86	100	
Sample Point Location	Outlet of ESP			
% RDF	35	37	23	
Stack Gas Data				
Flow (Nm^3/s-dry)	39.0	38.8	37.5	
Flow (dscfm)	82,612	82,273	79,545	
Temperature (°C)	198	201	201	
Temperature (°F)	388	394	394	
Moisture (%)	7.9	7.0	7.2	
Oxygen, dry (%)	10.2	10.1	9.6	
CO_2, dry (%)	9.1	8.5	9.2	
Particulate Emissions				
g/Nm^3-dry	0.044	0.060	0.172	
g/Nm^3-dry @ 12% CO_2	0.057	0.085	0.224	
gr/dscf	0.019	0.026	0.075	
gr/dscf @ 12% CO_2	0.025	0.037	0.098	
ng/J	21.5	34.4	86.0	
lb/10^6 Btu	0.05	0.08	0.20	
Average Opacity				
Control Device				
Type	MC/ESP			
Operating Parameter[1]	181	182	184	
Design Parameter[1]	188			
Design Flow Rate (ACFM)	133,000			

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

PLANT HG4[106,107]

TEST SUMMARY SHEETS
(Particulates Only)

Test Number	One	Two	Three	Average
General Data				
Date	5/11/79	5/11/79		
% Isokinetic				
Boiler Load (% of design)	95	92		91
Sample Point Location	Outlet of ESP			
% RDF	51	51		36
Stack Gas Data				
Flow (Nm^3/s-dry)	33.1	35.7		
Flow (dscfm)	70,154	75,622		75,506
Temperature (°C)	199	203		201
Temperature (°F)	391	398		393
Moisture (%)	8.3	8.4		7.4
Oxygen, dry (%)	9.7	10.3		10.2
CO_2, dry (%)	9.1	8.6		9.0
Particulate Emissions				
g/Nm^3-dry	0.819	0.238		0.126
g/Nm^3-dry @ 12% CO_2	1.08	0.332		0.167
gr/dscf	0.358	0.104		0.055
gr/dscf @ 12% CO_2	0.472	0.145		0.073
ng/J	426	129		68.8
lb/10^6 Btu	0.99	0.30		0.16
Average Opacity				
Control Device				
Type	MC/ESP			
Operating Parameter[1]	199	188		192
Design Parameter[1]	188			
Design Flow Rate (ACFM)	133,000			

[1]For WS, pressure drop = "H_2O. For ESP, SCA = ft^2/1000 ACFM.
For FF, A/C = ft/min.

C.2 VISIBLE EMISSIONS DATA

In this section opacity data collected in accordance with EPA Method 9 procedures from various nonfossil fuel fired facilities are presented. Most of the data are from tests conducted by EPA to aid in the development of New Source Performance Standards. The data are summarized by six minute averages. For each facility, general data such as boiler type, rated steam capacity, and control device type and operating parameters are presented with the opacity data.

Some of the following Method 9 tests were conducted simultaneously with the Method 5 tests reported in Section C.1. When this is the case the Method 5 test is identified in the footnotes of the data tables. If no corresponding Method 5 test is identified, the Method 9 test was not conducted simultaneously with the Method 5 test shown in Section C.1, or no Method 5 test data is available for this site.

SUMMARY OF VISIBLE EMISSIONS

PLANT AE[a,b]

Test Date: 11/12/80

Boiler Type	-	Spreader Stoker
Boiler Capacity (lb steam/hr)	-	120,000
Boiler Load (% of capacity)	-	88
Control Device	-	Venturi Wet Scrubber
Design Pressure Drop ("H_2O")	-	6-8
Operating Pressure Drop ("H_2O")	-	6-8
Fuel	-	80% bark/20% sawdust and wood trim

Time Period (minutes)	Average Opacity (%) Set 1	Set 1 (cont'd)	Set 1 (cont'd)
0-5	13.8	17.3	19.0
6-11	14.8	16.2	22.1
12-17	15.0	17.9	19.6
18-23	15.4	18.3	16.9
24-29	16.5	15.6	16.3
30-35	15.6	16.3	17.5
36-41	16.0	17.7	16.3
42-47	16.7	17.3	20.0
48-53	17.7	15.4	17.7
54-59	17.9	15.0	20.0

Average all sets: 17.1

[a]Tested by the EPA.

[b]Reference 108-110.

SUMMARY OF VISIBLE EMISSIONS

PLANT AF[a,b]

Test Date: 11/10/80

Boiler Type	-	Spreader Stoker
Boiler Capacity (lb steam/hr)	-	120,000
Boiler Load (% of capacity)	-	78
Control Device	-	Impingement Wet Scrubber
Design Pressure Drop ("H_2O")	-	6-8
Operating Pressure Drop ("H_2O")	-	5.2
Fuel	-	90% bark/10% wood trim

Average Opacity (%)

Time Period (minutes)	Set 1	Set 1 (cont'd)	Set 1 (cont'd)
0-55	25.0	19.2	24.4
6-11	24.6	19.8	24.4
12-17	23.5	19.4	22.7
18-23	22.7	19.4	20.2
24-29	24.8	20.0	25.6
30-35	25.0	24.0	24.6
36-41	24.2	25.0	24.8
42-47	24.2	26.9	22.1
48-53	19.8	24.8	20.8
54-59	19.4	24.0	21.3

Average all sets: 22.9

[a]Tested by the EPA.

[b]Reference 111-113.

SUMMARY OF VISIBLE EMISSIONS

PLANT BA[a,b]

Test Date: 11/11/80

Boiler Type	-	Spreader Stoker
Boiler Capacity (lb steam/hr)	-	110,000
Boiler Load (% of capacity)	-	78
Control Device	-	ESP
Design SCA (ft^2/1000 ACFM)	-	177
Fuel	-	Bark

Average Opacity (%)

Time Period (minutes)	Set 1	Set 1 (cont'd)	Set 1 (cont'd)
0-5	0.0	0.0	0.0
6-11	0.0	0.0	0.0
12-17	0.0	3.3	0.0
18-23	0.0	0.0	0.4
24-29	0.0	3.5	3.3
30-35	0.0	0.0	0.0
36-41	0.0	0.8	0.0
42-47	0.0	1.3	0.0
48-53	0.6	1.7	0.0
54-59	0.0	0.6	6.5

Average all sets: 0.5

[a]Tested by the EPA.

[b]Reference 114-115.

SUMMARY OF VISIBLE EMISSIONS

PLANT BC[a,b]

Emission Source: Stack

Test Date: 11/19-22/80

Boiler Type	-	Dutch Oven
Boiler Capacity (lb steam/hr)	-	150,000 (three 50,000 units)
Boiler Load (% of capacity)	-	91
Control Devices	-	MC/FF
Design Air-to-Cloth Ratio	-	3.64
Air-to-Cloth Radio During Testing	-	2.98
Fuel	-	Salt-laden Hog Fuel

Average Opacity (%)

Time Period (minutes)	Set 1	Set 1 (cont'd)	Set 1 (cont'd)	Set 2	Set 2 (cont'd)	Set 2 (cont'd)	Set 3	Set 3 (cont'd)	Set 3 (cont'd)
0-5	7.7	11.5	10.6	1.5	0.6	1.7	0.0	0.0	0.0
6-11	9.0	12.5	6.9	2.1	0.6	1.9	0.0	0.0	0.0
12-17	8.8	11.0	11.3	2.3	2.9	1.7	0.0	0.0	0.0
18-23	7.9	9.8	11.7	2.1	2.9	6.0	0.0	0.0	0.0
24-29	9.4	10.0	10.4	1.7	2.1	8.8	0.0	0.0	0.0
30-35	6.5	8.8	6.5	0.8	1.9	7.7	0.0	0.0	0.0
36-41	5.4	9.4	8.3	0.0	0.8	4.2	0.6	0.0	0.0
42-47	9.6	9.4	5.2	0.6	0.0	0.6	0.0	0.0	0.0
48-53	10.0	8.8	6.3	0.2	4.2	1.9	2.5	0.0	0.0
54-59	13.5	11.9	7.3	2.1	2.3	0.0	0.0	0.0	

Average of all sets: 3.8

[a]Tested by the EPA simultaneously with test BC2.

[b]Reference 116.

SUMMARY OF VISIBLE EMISSIONS

PLANT BH[a,b]

Emission Point: Riverside ESP

	Boiler #4	Boiler #5
Test Date: 9/24-25/80		
Boiler Type	- Pulverized Coal	- Spreader Stoker
Boiler Capacity (lb steam/hr)	- 140,000	- 200,000
Boiler Load (% of capacity)	- 48	- 88
Control Devices	- MC/ESP	- MC/ESP
Design SCA (ft^2/1000 ACFM)	- 460	- 460
Operating SCA during testing (ft^2/1000 ACFM)	- 486	- 420
Fuel	- Coal	- Bark

Average Opacity (%)

Time Period (minutes)	Set 1	Set 1 (cont'd)	Set 1 (cont'd)	Set 2	Set 2 (cont'd)	Set 3	Set 3 (cont'd)	Set 3 (cont'd)
0-5	0.0	0.0	0.0	1.7	0.0	0.0	0.0	0.0
6-11	0.0	0.0	0.0	1.0	0.0	0.0	1.0	0.0
12-17	0.0	0.0		0.0	0.0	0.0	0.0	0.0
18-23	0.0	1.6		0.0	0.0	0.0	0.0	0.0
24-29	0.4	0.0		0.0	0.0	0.0	0.0	0.0
30-35	0.0	0.0		0.0		0.0	0.0	0.0
36-41	0.0	0.0		0.0		0.0	0.0	0.0
42-47	0.0	0.0		0.0		0.0	0.0	0.0
48-53	0.0	0.0		0.0		0.0	0.0	0.0
54-59	0.0	0.0		0.0		0.0	0.0	

Average of all sets: 0.1

[a]Tested by the EPA simultaneously with test BH6.

[b]Reference 117.

SUMMARY OF VISIBLE EMISSIONS

PLANT BH[a,b]

Emission Point: Trackside ESP

Test Date: 9/24-25/80	Boiler #4	Boiler #5
Boiler Type	- Pulverized Coal	- Spreader Stoker
Boiler Capacity (lb steam/hr)	- 140,000	- 200,000
Boiler Load (% of capacity)	- 48	- 88
Control Devices	- MC/ESP	- MC/ESP
Design SCA (ft^2/1000 ACFM)	- 460	- 460
Operating SCA during testing (ft^2/1000 ACFM)	- 486	- 420
Fuel	- Coal	- Bark

Average Opacity (%)

Time Period (minutes)	Set 1	Set 1 (cont'd)	Set 2	Set 2 (cont'd)	Set 3	Set 3 (cont'd)	Set 3 (cont'd)
0-5	0.0	0.0	4.6	0.0	0.0	0.0	0.0
6-11	0.0	0.0	0.2	0.0	0.0	0.0	0.0
12-17	0.0	0.0	0.0	0.0	0.0	0.0	0.0
18-23	0.0	0.0	0.0	0.0	0.0	0.0	0.0
24-29	0.0	0.0	0.0	0.0	0.0	0.0	0.0
30-35	0.0	0.0	0.0		0.0	0.0	0.0
36-41	0.0	0.0	0.0		0.0	0.0	0.0
42-47	1.5	0.0	0.0		0.0	0.0	0.0
48-53	0.0	0.0	0.0		0.0	0.0	0.0
54-59	0.2	0.0	0.0		0.0	0.0	0.0

Average of all sets: 0.1

[a]Tested by the EPA simultaneously with test BH6.

[b]Reference 117.

SUMMARY OF VISIBLE EMISSIONS

PLANT BH[a,b,c]

Emission Point: Riverside Stack

Test Date: 12/12-15/79

	Boiler #4	Boiler #5
Boiler Type	- Pulverized Coal	- Spreader Stoker
Boiler Capacity (lb steam/hr)	- 140,000	- 200,000
Boiler Load (% of capacity)	- 94	- 46
Control Device	- ESP	- ESP
Design SCA (ft^2/1000 ACFM)	- 460	- 460
Operating SCA (ft^2/1000 ACFM)(during testing)	- 486	- 499
Fuel	- 100% Coal	- 100% Bark

Average Opacity (%)

Time Period (minutes)	Set 1	Set 1 (cont'd)	Set 1 (cont'd)	Set 2	Set 2 (cont'd)	Set 2 (cont'd)	Set 3	Set 3 (cont'd)	Set 3 (cont'd)
0-5	14.2	15.2	15.2	15.0	15.0	15.0	10.4	12.7	20.4
6-11	15.0	23.1	15.0	15.0	15.0		17.9	10.6	11.9
12-17	15.0	14.0	15.0	19.0	15.0		14.0	14.0	10.0
18-23	15.4	18.1		15.0	15.0		11.0	10.6	11.9
24-29	17.9	15.0		15.0	22.3		10.6	12.7	
30-35	15.2	14.6		16.5	15.0		10.2	12.3	
36-41	14.6	15.0		15.0	15.0		21.0	11.9	
42-47	15.0	13.5		15.0	15.0		10.0	11.5	
48-53	12.7	15.0		15.0	15.0		10.0	10.6	
54-59	21.3	15.4		17.5	15.0		11.7	11.5	

Average all sets: 14.5

[a] Tested by the EPA.

[b] Conducted simultaneously with the Method 5 test designated B7, B8, B9, and the data were not considered representative for the reasons discussed in Section C.1.

[c] Reference 118.

SUMMARY OF VISIBLE EMISSIONS

PLANT BH[a,b,c]

Emission Point: Trackside Stack

Test Date: 12/12-15/79

	Boiler #4	Boiler #5
Boiler Type	- Pulverized Coal	- Spreader Stoker
Boiler Capacity (lb steam/hr)	- 140,000	- 200,000
Boiler Load (% of capacity)	- 94	- 46
Control Device	- MC/ESP	- MC/ESP
Design SCA (ft^2/1000 ACFM)	- 460	- 460
Operating SCA (ft^2/1000 ACFM)(during testing)	- 486	- 499
Primary Fuel	- Coal	- 100% Bark

Average Opacity (%)

Time Period (minutes)	Set 1	Set 1 (cont'd)	Set 2	Set 2 (cont'd)	Set 2 (cont'd)	Set 3	Set 3 (cont'd)	Set 3 (cont'd)
0-5	14.2	15.0	15.0	15.0	20.4	10.2	11.7	10.6
6-11	15.0	15.0	15.4	15.0	15.0	12.7	10.6	10.0
12-17	15.0	14.0	15.0	15.0	15.0	10.4	10.6	10.8
18-23	15.4	15.0	15.0	16.7	15.0	10.0	10.4	10.6
24-29	14.0	19.0	15.0	15.0	15.0	17.9	13.3	
30-35	14.6	14.2	15.8	15.0		10.8	10.0	
36-41	14.6	15.0	15.0	15.0		10.2	12.3	
42-47	19.6	15.0	15.0	15.0		10.0	12.7	
48-53	13.1	15.0	15.0	15.0		10.0	21.0	
54-59	15.0	15.4	15.0	15.0		10.4	14.0	

Average of all sets: 14.0

[a]Tested by the EPA.

[b]The test was conducted simultaneously with the Method 5 test designated B7, B8, B9 and the data were not considered representative for reasons discussed in Section C.1.

[c]Reference 118.

SUMMARY OF VISIBLE EMISSIONS

PLANT BI[a,b,c]

Emission Point: #7 Precipitator

Test Date: 12/6/79, 2/12-13/80

	Boiler #7	Boiler #8
Boiler Type.	- Spreader Stoker/ Traveling Grate	- Spreader Stoker/ Traveling Grate
Boiler Capacity (lb steam/hr)	- 240,000	- 325,000
Boiler Load (% of capacity)	- 87	- 87
Control Device	- ESP	- ESP
Design SCA (ft^2/1000 ACFM)	- 300	- 300
Operating SCA (ft^2/1000 ACFM) (during testing)	- 321	- 320
Fuel	- 25% Bark/75% Coal	- 25% Bark/75% Coal

Average Opacity (%)

Time Period (minutes)	Set 1	Set 1 (cont'd)	Set 1 (cont'd)	Set 1 (cont'd)	Set 2	Set 2 (cont'd)	Set 3	Set 3 (cont'd)	Set 4	Set 4 (cont'd)
0-5	0	0.8	0	0	0	2.3	0	0.21	0	0
6-11	0	0	0	0	0	0.4	0	1.8	0	0
12-17	0	1.0	0	0	0.6	2.9	0	0	0	0
18-23	0	8.8	0	0	2.1	0	0	0	0	
24-29	0	10.2	0	0	2.7	0	0	0	0	
30-35	0	5.4	0	0	0	0	0	0	0	
36-41	0	0	0		0.4	0	0	0	0	
42-47	4.4	0	0		0	0	0	0	0	
48-53	1.7	0	0		0	0	0	0	0	
54-59	1.9	0	0		3.1		0		0	

Average of all sets: 0.6

[a]Tested by the EPA.

[b]Reference 119.

[c]Conducted simultaneously with test BI1.

SUMMARY OF VISIBLE EMISSIONS

PLANT BI[a,b,c]

Emission Point: #8 Precipitator

Test Date: 2/12-13/80

	Boiler #7	Boiler #8
Boiler Type	- Spreader Stoker/ Traveling Grate	- Spreader Stoker/ Traveling Grate
Boiler Capacity (lb steam/hr)	- 240,000	- 325,000
Boiler Load (% of capacity)	- 87	- 87
Control Device	- ESP	- ESP
Design SCA (ft^2/1000 ACFM)	- 300	- 300
Operating SCA (ft^2/1000 ACFM) (during testing)	- 321	- 320
Fuel	- 25% Bark/75% Coal	- 25% Bark/75% Coal

Average Opacity (%)

Time Period (minutes)	Set 1	Set 1 (cont'd)	Set 1 (cont'd)	Set 1 (cont'd)	Set 2	Set 2 (cont'd)	Set 3	Set 3 (cont'd)	Set 4	Set 4 (cont'd)
0-5	0	1.0	0	0	0	1.5	0	0	0	0
6-11	0	0	0	0	0.2	0.4	0	0.6	0	0
12-17	0	1.0	0	0	0	1.5	0	0	0	0
18-23	0	12.5	0		0.8	0	0	0	0	
24-29	0	14.8	0		0.6	0	0	0	0	
30-35	0	7.5	0		0	0	0	0	0	
36-41	0	0	0		0	0	0	0	0	
42-47	2.5	0	0		0	0	0	0	0	
48-53	0.3	0	0		0	0	0	0	0	
54-59	18.8	0	0		1.7		0		0	

Average of all sets: 0.8

[a]Tested by the EPA.

[b]Reference 119.

[c]Conducted simultaneously with test BI1.

SUMMARY OF VISIBLE EMISSIONS

PLANT BJ[120,121]

Test Dates: 5/14-17/80, 6/27/79

Boiler Type	-	Spreader Stoker
Boiler Capacity (lbs steam/hr)	-	600,000
Boiler Load (% of capacity)	-	75% - 82%
Control Device	-	ESP
Design SCA (ft^2/1000 ACFM)	-	356
Operating SCA (ft^2/1000 ACFM)	-	460
Fuel	-	60% Bark and sawdust/40% Oil

Time Period (minutes)	Average Opacity				
	Set 1	Set 2	Set 3	Set 4	Set 5[a]
0-5	0	0	0	0	0
6-11	0	0	0	0	0
12-17	0	0	0	0	0

[a]Set 5 was conducted simultaneously with test BJ1.

SUMMARY OF VISIBLE EMISSIONS

PLANT BO[122]

Test date: 5/26/76

Boiler Type	-	Spreader Stoker
Boiler Capacity	-	180,000 lb/hr steam
Boiler Load (% of capacity)	-	96
Control Device	-	Impingement Wet Scrubber
Pressure drop during testing	-	6-8
Fuel	-	Hog Fuel

Average Opacity (%)

Test Period (minutes)	Set 1	Set 2	Set 3	Set 4
0-5	9.6	10.2	21.1	20.8
6-11	10.2	11.5	20.0	26.7
12-17		11.5		

Average of all sets: 15.7

SUMMARY OF VISIBLE EMISSIONS

PLANT BP[123]

Test Date: 2/7/78

Boiler Type	-	Spreader Stoker
Boiler Capacity (lb steam/hr)	-	40,000 (two 20,000 lb/hr units)
Boiler Load (% of capacity)	-	95
Control Device	-	Impingement Wet Scrubber
Pressure drop during testing	-	7-13 in H_2O
Fuel	-	Hog Fuel and Sanderdust

Average Opacity (%)

Time Period (minutes)	Set 1	Set 2
0-5	15.8	15.4
6-10	20.2	19.0

Average of all sets: 17.6

SUMMARY OF VISIBLE EMISSIONS

PLANT DD[124]

Emission Point: Stack of Boiler No. 2

Test Date: 12/16-17/78[a]

Boiler Type	-	Spreader Stoker
Boiler Capacity (lb steam/hr)	-	288,000
Boiler Load (% of Capacity)	-	68
Control Device	-	MC
Fuel	-	Bagasse

	Time Interval (minutes)	Average Opacity (%)
Set 1	6	21.9
Set 2	6	18.7
Set 3	6	16.6
Set 4	6	20.6
Set 5	6	17.7
Set 6	6	16.4

Average of all sets: 18.6

[a]Conducted simultaneously with test DD1.

SUMMARY OF VISIBLE EMISSIONS

PLANT FB[a,b]

Test Date: 11/7/80

Boiler Type	-	Overfeed Stoker
Boiler Capacity (lb steam/hr)	-	135,000
Boiler Load (% of capacity)	-	79
Control Devices	-	MC/ESP
Design SCA (ft^2/1000 ACFM)	-	316
Fuel	-	Municipal Solid Waste

Average Opacity (%)

Time Period (minutes)	Set 1	Set 1 (cont'd)	Set 1 (cont'd)
0-5	0.2	2.2	0.0
6-11	1.7	4.6	0.0
12-17	11.9	11.3	0.0
18-23	10.6	10.6	0.0
24-29	4.2	6.9	0.0
30-35	0.0	14.4	0.0
36-41	1.9	0.4	0.0
42-47	0.4	0.0	0.0
48-53	1.7	0.0	4.2
54-59	0.2	0.0	1.9

Average of all sets: 3.0

[a]Tested by the EPA.

[b]Reference 125,126.

SUMMARY OF VISIBLE EMISSIONS

PLANT FC[a,b]

Test Date: 1/21/81

Boiler Type	-	Overfeed Stoker
Boiler Capacity (lb steam/hr)	-	175,000
Boiler Load (% of capacity)	-	82
Control Device	-	ESP
Design SCA (ft^2/1000 ACFM)	-	209
Fuel	-	Municipal Solid Waste

Average Opacity (%)

Time Period (minutes)	Set 1	Set 1 (cont'd)	Set 1 (cont'd)
0-5	4.2	2.7	5.2
6-11	4.6	3.3	4.2
12-17	5.0	2.9	2.3
18-23	4.8	3.5	1.3
24-29	5.2	4.4	1.9
30-35	6.3	3.3	1.7
36-41	5.2	5.6	3.3
42-47	5.0	4.6	5.8
48-53	4.4	2.3	4.6
54-59	5.0	3.1	1.7

Average of all sets: 3.9

[a]Tested by the EPA.

[b]Reference 127,128.

SUMMARY OF VISIBLE EMISSIONS

PLANT FD[a,b]

Emission Point: West Stack

Test Date: 11/6-7/79

Boiler Type	-	Ram-fed Controlled Air
Boiler Capacity (lb steam/hr)	-	10,000
Boiler Load (% of capacity)	-	76
Control Device	-	None
Fuel	-	Municipal Solid Waste

Average Opacity (%)

Time Period (minutes)	Set 1	Set 1 (cont'd)	Set 1 (cont'd)	Set 1 (cont'd)	Set 2	Set 2 (cont'd)	Set 3	Set 3 (cont'd)
0-5	14.4	15.4	12.3	13.3	13.8	17.5	15.0	16.9
6-11	15.6	14.4	13.5	12.9	16.3	21.9	14.6	16.5
12-17	10.0	12.3	15.4	12.9	17.9	19.2	12.9	14.0
18-23	12.3	12.5	12.9	12.3	20.2	16.7	14.8	14.4
24-29	11.9	14.0	14.2	12.9	17.5	18.5	19.6	
30-35	13.5	16.0	13.3		17.8	18.8	22.9	
36-41	14.4	14.0	12.3		17.3		17.3	
42-47	10.6	16.3	12.3		17.7		15.0	
48-53	11.9	14.2	12.9		16.7		17.9	
54-59	13.5	12.7	12.1		17.5		16.5	

Average of all sets: 15.1

[a]Tested by the EPA simultaneously with test FD3.

[b]Reference 129.

SUMMARY OF VISIBLE EMISSIONS

PLANT HF[a,b,c]

Test Dates: 4/30/79 - 5/1/79

Boiler Type	-	Spreader Stoker
Boiler Capacity (lb steam/hr)	-	200,000
Boiler Load (% of capacity)	-	80
Control Devices	-	Mechanical Collector/ESP
Design SCA (ft^2/1000 ACFM)	-	248
Fuel	-	Wet pulped RDF

Average Opacity (%)

Time Period (minutes)	Set 1[c]	Set 2	Set 3
0-5		5.8	0
6-11		5.8	0
12-17		6.7	0
18-23		9.2	0
24-29		7.5	0
30-35		9.2	0
36-41		12.5	0
42-47		7.5	0
48-53		7.5	0
54-59		7.5	0

Average of all sets: 4.0

[a]Reference 130-131.

[b]Data was obtained concurrently with test HF1. The set number corresponds to the Method 5 test run number.

[c]The average opacity for set 1 was shown in the test reports as 29 percent for one hour of readings. However, the data showing the actual readings was illegible so six minute averages could not be calculated for set 1. Also, data shown indicated proper Method 9 methods might not have been followed during this test run. Because of the doubts about the accuracy of the data, and the fact that data were not available to calculate the six minute averages, the opacity data from Run 1 were not used in NSPS development.

C.3 SO_2 EMISSION REDUCTION DATA

This section presents continuous monitoring data for eight industrial boiler wet FGD systems, one lime spray drying FGD system, and one fluidized-bed combustion system. The test data for five of the wet FGD systems and the lime spray drying systems were presented and discussed in Chapter 4 with regard to the level of SO_2 removal achievable with well designed, operated, and maintained FGD systems, as is the fluidized-bed system. This section contains daily test results for each of these sites as well as the continuous monitoring data for three wet FGD systems that were, for various reasons, not considered to be representative of well designed and operated FGD systems. The reasons why these latter sites were not considered to be representative are documented in their respective site descriptions.

All the continuous monitoring tests of FGD systems were conducted by EPA. At the start of each test program, the continuous monitors were subjected to performance specification tests as delineated in 40 CFR 60, Appendix B (proposed revisions as of 10 October 1979). All sampling and analysis during the performance tests were performed according to EPA 40 CFR 60 Appendix A, Methods 1 through 6. SO_2 emission rates in ng/J (lb/10^6 Btu) were calculated from measured gas stream concentrations combined with ultimate analyses and heating values of the fuel fired at each site. The SO_2 removal efficiencies were then determined by comparison of inlet and outlet emission rates. Only test days with more than 18 hours of test data are reported.

Each site description that follows provides a brief process description and daily average monitoring results in both tabular and graphical form.

Location I[132]

The FGD system monitored at plant location I is a Peabody tray and quench water scrubber. The scrubbing medium is a 50 weight percent sodium hydroxide (NaOH) aqueous solution with a 35 gallon per minute make up. A scrubber handling flue gases from a 150,000 lbs. steam/hr capacity Babcock and Wilcox (B&W) pulverized coal boiler was monitored. The boiler is fired using Southern Illinois subbituminous coal with a sulfur content between 3.55 to 3.73 weight percent.

The daily averaged test results are presented in Table C.3-1 to C.3-3. Continuous monitoring data were obtained for 30 test days. The hourly averaged boiler loadings ranged from 55,000 to 120,000 lbs/hr. with an average of about 72,000 lbs/hr during the test period. Figure C.3-1 illustrates daily average SO_2 removal efficiency, boiler load, and scrubbing solution pH.

TABLE C.3-1. DAILY AVERAGE SO_2 REMOVAL RESULTS SODIUM SCRUBBING PROCESS - LOCATION I[a,b]

Test Day[a]	SO_2 Emission Rate at Scrubber Inlet: ng/J	SO_2 Emission Rate at Scrubber Inlet: lb/million Btu	SO_2 Emission Rate at Scrubber Outlet: ng/J	SO_2 Emission Rate at Scrubber Outlet: lb/million Btu	Percent SO_2 Removal
1	2380	5.5	55	0.1	97.7
2	2377	5.5	58	0.1	97.6
3	2403	5.6	59	0.1	97.6
4	2385	5.5	64	0.1	97.3
5	2274	5.3	54	0.1	97.3
6	2341	5.4	69	0.2	97.0
7	2406	5.6	83	0.2	96.5
8	2420	5.6	96	0.2	96.1
9	2396	5.6	108	0.3	95.5
10	2404	5.6	81	0.2	96.7
11	2392	5.6	74	0.2	96.9
12	2433	5.7	85	0.2	96.5
13	2450	5.7	90	0.2	96.3
14	2372	5.5	83	0.2	96.5
15	2433	5.7	87	0.2	96.4
16	2461	5.7	96	0.2	96.1
17	2420	5.6	83	0.2	96.6
18	2421	5.6	99	0.2	95.9
19	2376	5.5	81	0.2	96.6
20	2365	5.5	91	0.2	96.2
21	2354	5.5	90	0.2	96.2
22	2335	5.4	92	0.2	96.1
23	2480	5.8	80	0.2	96.7
24	2724	6.3	112	0.3	95.4
25	2229	5.2	267	0.6	88.3
26	2132	5.0	90	0.2	95.7
27	2109	4.9	85	0.2	96.0
28	2125	4.9	86	0.2	96.0
29	2072	4.8	62	0.1	96.9
30	1961	4.6	62	0.1	96.8
30 Day Average	2348	5.5	87	0.2	96.2

[a] 18 Hours/day minimum test time.

[b] Reference 133.

TABLE C.3-2. DAILY SUMMARY OF HOURLY BOILER LOADS SODIUM SCRUBBING PROCESS - LOCATION I[a,b]

Test Day[a]	Minimum Hourly Boiler Load (1000 lb steam/hr)	24-Hour Average Boiler Load (1000 lb steam/hr)	Maximum Hourly Boiler Load (1000 lb steam/hr)
1	77	81	86
2	70	77	81
3	75	79	98
4	73	83	120
5	73	77	80
6	81	84	90
7	66	68	75
8	61	69	80
9	70	73	75
10	67	70	73
11	70	73	77
12	61	67	72
13	60	66	68
14	70	70	70
15	55	58	60
16	55	55	55
17	55	55	55
18	60	73	80
19	78	81	85
20	65	67	70
21	65	71	80
22	70	79	82
23	78	80	82
24	70	78	80
25	70	77	80
26	65	65	70
27	60	76	80
28	60	70	85
29	65	65	65
30	50	62	110

[a] 18 Hours/day minimum test time.

[b] Reference 133.

TABLE C.3-3. DAILY SUMMARY OF pH LEVELS SODIUM SCRUBBING PROCESS - LOCATION I[a,b]

Test Day[a]	Minimum pH Reading	Daily Average pH Level	Maximum pH Reading
1	7.8	8.0	8.2
2	7.7	8.1	8.3
3	7.8	7.9	8.2
4	7.7	8.0	8.3
5	7.8	8.0	8.1
6	7.8	7.9	8.0
7	7.9	8.0	8.2
8	8.2	8.2	8.2
9	7.9	8.0	8.1
10	8.1	8.1	8.2
11	7.8	8.1	8.7
12	8.2	8.8	9.4
13	8.0	8.1	8.1
14	8.0	8.0	8.0
15	8.0	8.0	8.0
16	8.1	8.1	8.1
17	8.0	8.0	8.0
18	7.8	7.8	7.9
19	-	7.9	-
20	-	8.5	-
21	8.0	8.1	8.1
22	7.8	8.0	8.3
23	-	8.0	-
24	-	8.3	-
25	-	8.2	-
26	8.0	8.4	8.8
27	-	8.2	-
28	-	8.2	-
29	8.0	8.2	8.4
30	7.8	8.1	8.4

[a]No minimum or maximum readings are given on those test days for which only one reading was taken.

[b]Reference 134.

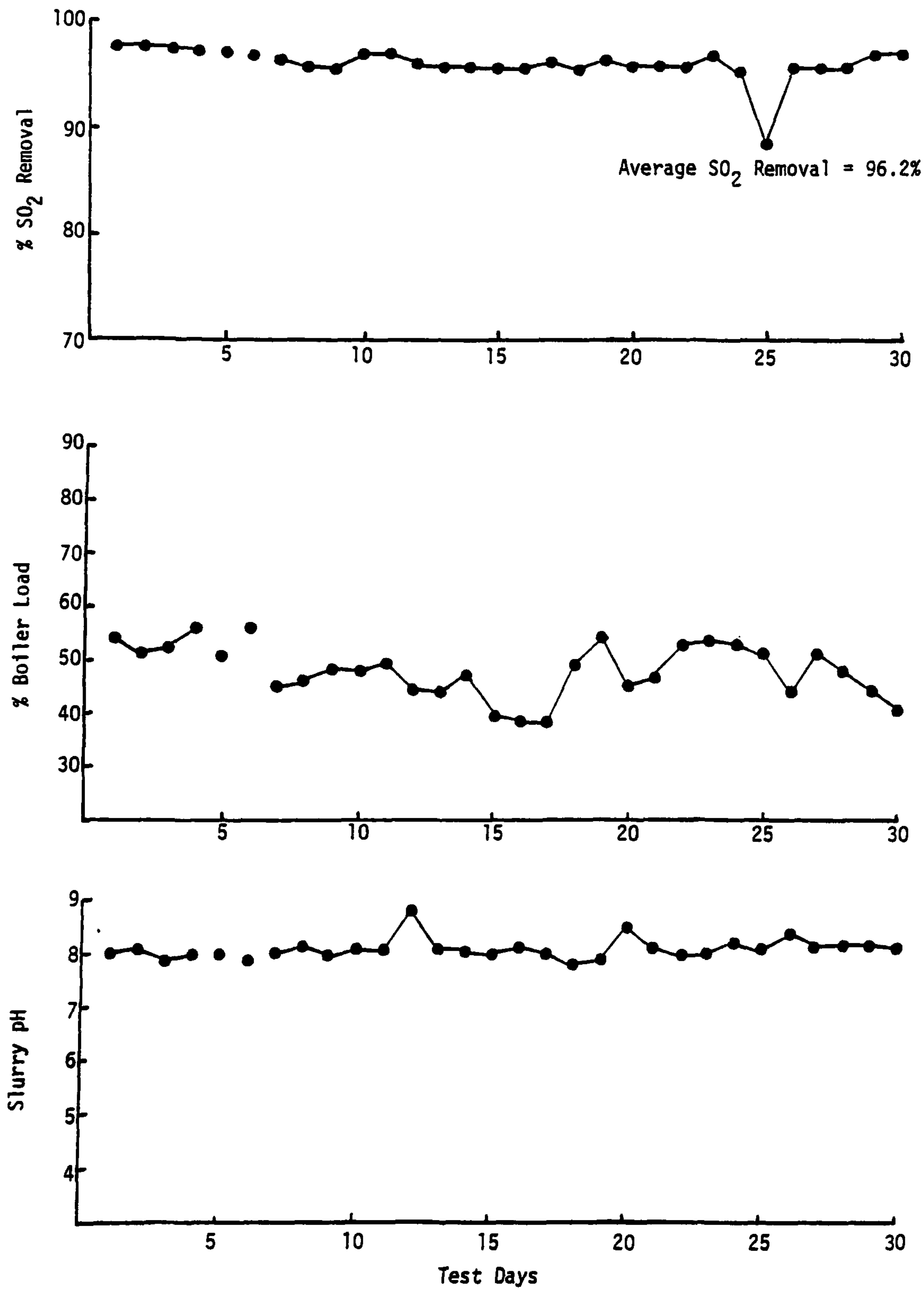

Figure C.3-1. Daily average SO_2 removal, boiler load, slurry pH for the sodium scrubbing process at Location I.

Location II[135]

The FGD system monitored at plant location II is an Airpol Venturi scrubber. The scrubbing medium is an aqueous solution of sodium hydroxide (NaOH) and sodium carbonate (Na_2CO_3). The scrubber handles flue gases from two oil-fired steam generators, a hog fuel-fired steam generator and a recovery boiler. The boilers are fired with No. 6 fuel oil containing four percent sulfur with Gross Calorific Value (GCV) of 39,929 kJ/kg (17,167 Btu/lb). Each unit produces 100,000 lb of steam/hour. These units operate in tandem with the hog-fueled unit which supplied up to 50 percent of the total process steam demand. The amount of steam produced by the hog-fired unit depended on the supply of the hog fuel. Therefore, under normal operating conditions, there were large and unpredictable fluctuations in the steam demand on the two oil-fired units.

The daily averaged test results are presented in Table C.3-4. Continuous monitoring data was obtained for 22 test days. The hourly combined averaged boiler loadings ranged from 35,000 to 265,000 lbs/hr with an average of about 103,000 lbs/hr during the test period.

Despite the fact that average SO_2 removal for the test period was greater than 90 percent, the wide fluctuations in removal efficiency are not considered to be representative of a well-operated FGD system.[136]

TABLE C.3-4. DAILY AVERAGE SO_2 REMOVAL RESULTS-SODIUM SCRUBBING PROCESS-LOCATION II[a,b]

Test Day	SO_2 Emission Rate at Scrubber Inlet		SO_2 Emission Rate at Scrubber Outlet		Percent SO_2 Removal
	ng/J	lb/Million Btu	ng/J	lb/Million Btu	
1	1827	4.3	52	0.1	97.2
2	1830	4.3	27	0.1	98.5
3	1829	4.3	480	1.1	73.7
4	1986	4.6	46	0.1	97.7
5	2088	4.9	149	0.3	92.9
6	2334	5.4	67	0.2	97.1
7	2220	5.2	140	0.3	93.7
8	1960	4.6	119	0.3	93.9
9	2116	4.9	28	0.1	98.7
10	2224	5.2	109	0.3	95.1
11	2089	4.9	99	0.2	95.3
12	1882	4.4	544	1.3	71.1
13	1591	3.7	12	0.0	99.3
14	1429	3.3	23	0.1	98.4
15	1692	3.9	15	0.0	99.1
16	1532	3.6	347	0.8	77.3
17	2101	4.9	28	0.1	98.7
18	1670	3.9	24	0.1	98.6
19	1803	4.2	43	0.1	97.6
20	1889	4.4	752	1.7	60.2
21	1627	3.8	338	0.8	79.2
22	2818	6.6	69	0.2	97.6
22 Day Average	1934	4.5	160	0.4	91.7

[a] 18 hours/day minimum test time

[b] Reference 137

Location III[138]

Two FGD systems were monitored at plant location III. Both systems consist of dilute double alkali scrubbing in valve tray type absorbers supplied by Koch Engineering Company. SO_2 in the flue gas is absorbed by a regenerated caustic soda solution (0.1 M NaOH), forming a solution of soluble sodium salts. The absorber has a quench spray section at the inlet and full diameter chevron mist eliminators at the outlet. A portion of the circulating liquor containing a mixture of sodium sulfate is bled to a reactor/clarifier system where active alkali is regenerated by reacting the solution with a slurry of lime. The precipitated solids are further reacted and concentrated in a clarifier.

The individual scrubbers handle flue gases from coal-fired boilers No. 1 and No. 3. Each boiler is a spreader-stoker unit with a maximum rated capacity of 100,000 and 60,000 lbs/hour of steam, respectively, for boilers No. 1 and No. 3. Normal burning of eastern coal containing 1.7 to 2.7 percent sulfur, plus occasional lower sulfur waste oil results in flue gas generally containing 800 to 1,300 ppm of SO_2.

The daily average test results are presented in Tables C.3-5 through C.3-10. Continuous monitoring data was obtained for 17 and 24 test days for the FGD systems on boiler No. 1 and No. 3, respectively. Figures C.3-2 and C.3-3 present daily SO_2 removal boiler load, and slurry pH for the two boilers.

TABLE C.3-5. DAILY AVERAGE SO_2 REMOVAL RESULTS
DUAL ALKALI PROCESS
LOCATION III (BOILER NO. 1)[139]

Test Day[a]	SO_2 Emission Rate at Scrubber Inlet		SO_2 Emission Rate at Scrubber Outlet		Percent SO_2 Removal
	ng/J	lb/Million Btu	ng/J	lb/Million Btu	
1	1659	3.8	194	0.5	88.2
2	1720	4.0	165	0.4	90.3
3	1698	4.0	163	0.4	90.4
4	1634	3.8	117	0.3	92.8
5	1594	3.7	97	0.2	93.6
6	1320	3.1	134	0.3	89.9
7	1235	2.9	93	0.2	92.4
8	1539	3.6	138	0.3	90.8
9	1806	4.2	101	0.2	94.6
10	2000	4.7	137	0.3	93.0
11	1680	3.9	156	0.4	90.6
12	1670	3.9	81	0.2	95.2
13	1619	3.8	172	0.4	89.4
14	1722	4.0	213	0.5	87.6
15	1811	4.2	134	0.3	92.6
16	1564	3.6	110	0.3	93.0
17	1706	4.0	135	0.3	92.1
17 Day Average	1646	3.8	138	0.3	91.6

[a]18 Hours/day minimum test time.

TABLE C.3-6 DAILY AVERAGE SO_2 REMOVAL RESULTS
DUAL ALKALI PROCESS
LOCATION III (BOILER NO. 3)[139]

Test Day[a]	SO_2 Emission Rate at Scrubber Inlet		SO_2 Emission Rate at Scrubber Outlet		Percent SO_2 Removal
	ng/J	$\frac{lb}{Million\ Btu}$	ng/J	$\frac{lb}{Million\ Btu}$	
1	1534	3.6	62	0.1	95.9
2	1223	2.9	64	0.1	94.8
3	1246	2.9	78	0.2	93.7
4	1247	2.9	70	0.2	94.5
5	1180	2.8	82	0.2	93.0
6	1275	3.0	73	0.2	94.1
7	1284	3.0	37	0.1	97.1
8	1215	2.8	40	0.1	96.7
9	1634	3.8	446	1.0	73.6
10	1678	3.9	342	0.8	79.2
11	1892	4.4	201	0.5	89.3
12	1631	3.8	85	0.2	94.9
13	1647	3.8	61	0.1	96.3
14	1715	4.0	70	0.2	95.9
15	1934	4.5	153	0.4	92.2
16	1997	4.6	177	0.4	91.1
17	2285	5.3	110	0.3	95.1
18	2084	4.8	137	0.3	93.2
19	1648	3.8	133	0.3	92.0
20	1652	3.8	139	0.3	91.6
21	1707	4.0	132	0.3	92.3
22	1628	3.8	108	0.3	93.4
23	1561	3.6	128	0.3	91.9
24	1647	3.8	150	0.3	91.1
24 Day Average	1606	3.7	128	0.3	92.2

[a]18 Hours/day minimum test time.

TABLE C.3-7. DAILY SUMMARY OF HOURLY BOILER LOADS
DUAL ALKALI PROCESS
LOCATION III (BOILER NO. 1)[a,b]

Test Day[a]	Minimum Hourly Boiler Load (1000 lb steam/hr)	24-Hour Average Boiler Load (1000 lb steam/hr)	Maximum Hourly Boiler Load (1000 lb steam/hr)
1	60	74	88
2	60	80	96
3	65	73	80
4	67	74	80
5	60	76	93
6	55	68	84
7	53	67	76
8	52	68	89
9	55	66	76
10	52	56	63
11	47	53	60
12	60	71	86
13	53	67	83
14	42	65	82
15	49	54	59
16	53	67	81
17	50	65	76

[a]18 Hours/day minimum test time.

[b]Reference 139.

TABLE C.3-8. DAILY SUMMARY OF pH LEVELS
DUAL ALKALI PROCESS
LOCATION III (BOILER NO. 1)[140]

Test Day	Minimum pH Reading	Daily Average pH Level	Maximum pH Reading
1	6.0	6.0	6.0
2	6.0	6.0	6.0
3	6.0	6.0	6.0
4	6.0	6.0	6.0
5	5.6	5.8	6.0
6	5.8	5.9	6.0
7	6.0	6.0	6.0
8	6.0	6.0	6.0
9	5.7	6.0	6.0
10	5.8	5.9	6.0
11	5.9	6.1	6.3
12	5.7	6.0	6.2
13	5.9	6.1	6.3
14	6.0	6.0	6.0
15	6.0	6.0	6.0
16	6.0	6.1	6.5
17	6.0	6.0	6.0

TABLE C.3-9. DAILY SUMMARY OF HOURLY BOILER LOADS
DUAL ALKALI PROCESS
LOCATION III (BOILER NO. 3)[a,b]

Test Day[a]	Minimum Hourly Boiler Load (1000 lb steam/hr)	24-Hour Average Boiler Load (1000 lb steam/hr)	Maximum Hourly Boiler Load (1000 lb steam/hr)
1	3	32	43
2	22	34	48
3	25	34	40
4	26	36	46
5	34	39	43
6	37	40	43
7	36	40	42
8	38	41	42
9	30	41	56
10	28	37	47
11	27	38	49
12	5	42	53
13	38	43	50
14	19	38	45
15	38	46	57
16	34	42	50
17	29	39	50
18	27	39	50
19	29	35	45
20	25	32	42
21	24	32	41
22	20	31	39
23	28	35	43
24	24	32	42

[a]18 Hours/day minimum test time.

[b]Reference 139.

TABLE C.3-10. DAILY SUMMARY OF pH LEVELS
DUAL ALKALI PROCESS
LOCATION III (BOILER NO. 3)[a,b]

Test Day[a]	Minimum pH Reading	Daily Average pH Level	Maximum pH Reading
1	5.2	5.8	6.2
2	5.0	6.0	6.5
3	5.8	6.0	6.1
4	5.8	6.0	6.0
5	5.8	6.0	6.2
6	5.8	5.9	6.0
7	5.9	6.0	6.2
8	5.8	6.0	6.2
9	6.0	6.0	6.0
10	-	-	-
11	-	-	-
12	-	-	-
13	-	-	-
14	-	-	-
15	5.9	6.0	6.1
16	5.9	6.0	6.2
17	6.0	6.1	6.1
18	6.0	6.0	6.0
19	6.0	6.0	6.0
20	4.7	5.8	6.1
21	6.0	6.0	6.1
22	6.0	6.0	6.1
23	6.0	6.0	6.0
24	6.0	6.0	6.0

[a]No pH data available for test days 10 through 14.

[b]Reference 140.

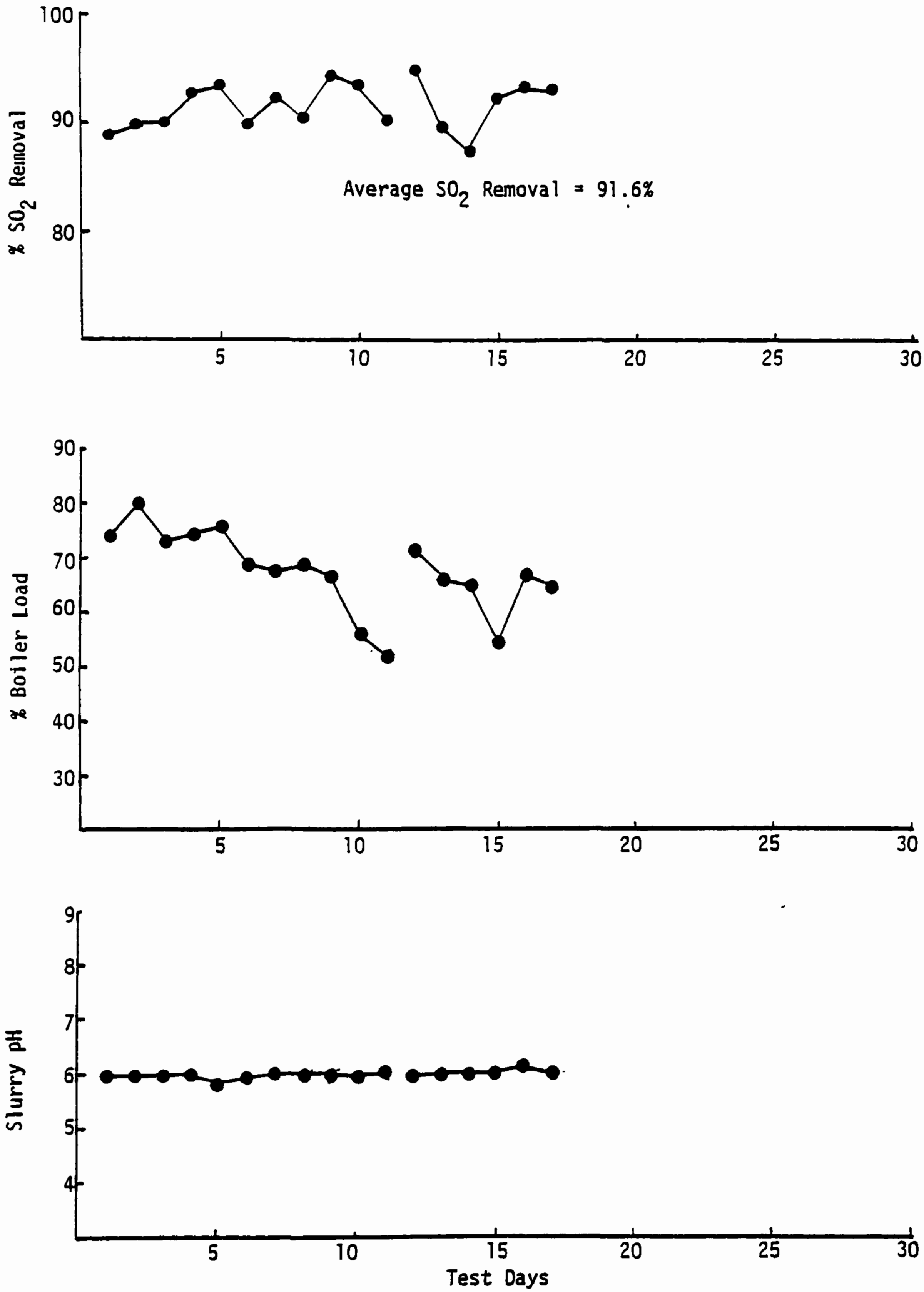

Figure C.3-2 Daily average SO_2 removal, boiler load, and slurry pH for the dual alkali scrubbing process at Boiler #1, Location III.

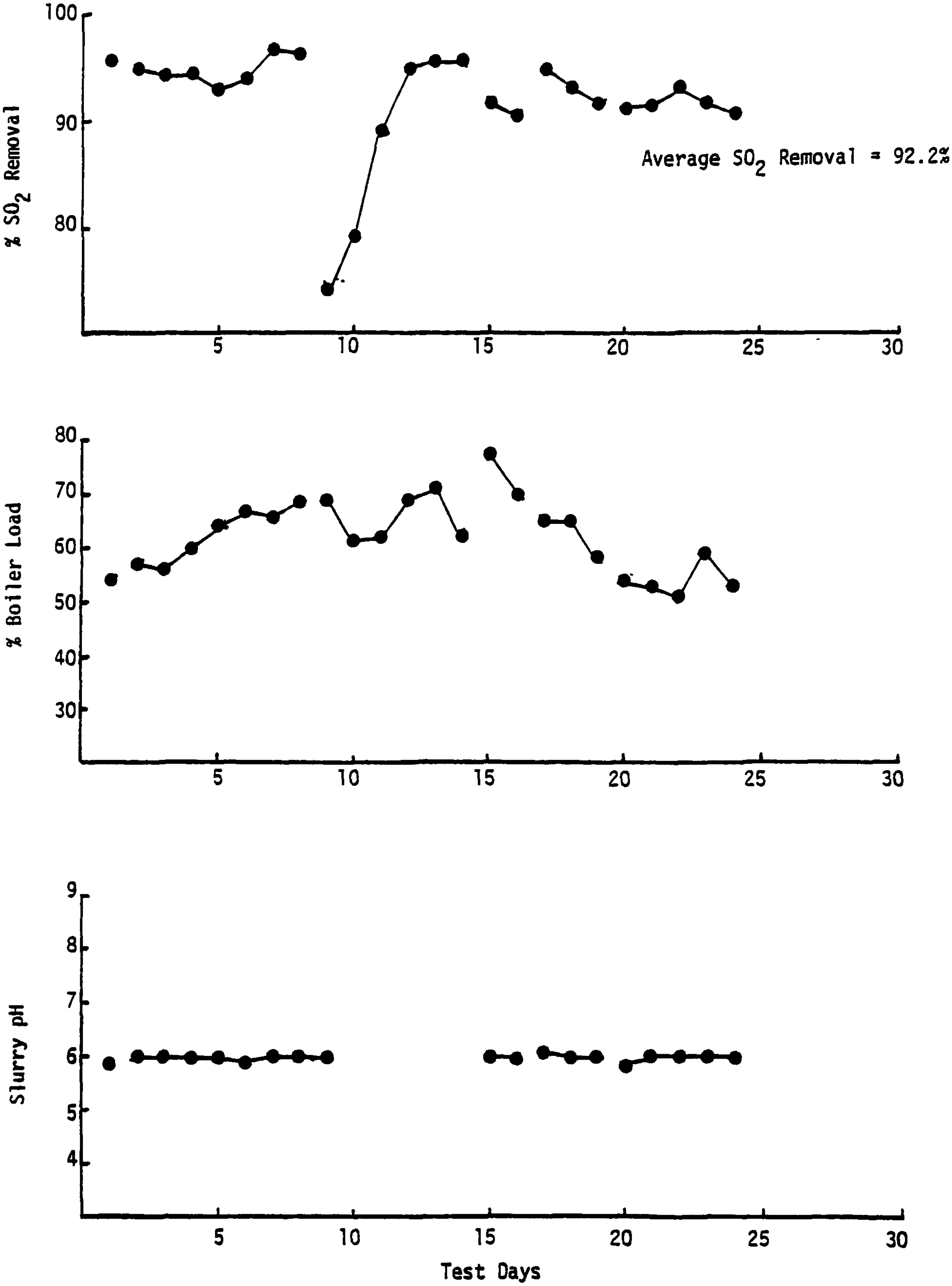

Figure C.3-3 Daily average SO_2 removal, boiler load, and slurry pH for scrubbing process at Boiler #3 Location III.

Location IV - Lime System[141]

Three data sets were taken on a lime/limestone FGD system at location IV. One of the tests monitored the system under lime sorbent operations and the two other tests monitored the system while it operated using limestone as a sorbent; in one of the two limestone tests, adipic acid was added to improve SO_2 removal efficiency.

Particulates are removed from the flue gas in a mechanical collector upstream of the absorber. The absorber is a two-stage unit with fresh solvent make-up being introduced at the second stage. Flue gas from the absorber enters a cyclonic mist eliminator before going to the stack.

The scrubber system was designed to treat the combined flue gas from seven small stoker boilers at the peak winter load of approximately 210×10^6 Btu/hr. Typical fuel burned at the facility is mid-west coal with a sulfur content of about 3.5 percent. The system has essentially unlimited turndown capability since it mixes air with flue gas to maintain a constant flue gas rate at low boiler loads. Consequently, SO_2 concentrations will vary from about 200 to 2000 ppm depending upon the boiler load. SO_2 emissions averaged 194 ng/J during the tests.

The daily average test results for operation with lime sorbent are presented in Tables C.3-11 through C.3-13. Continuous monitoring data was obtained for 29 days with overall average SO_2 removal of 91.2. Figure C.3-4 shows the daily SO_2 removal boiler load, and slurry pH levels.

TABLE C.3-11. DAILY AVERAGE SO_2 REMOVAL RESULTS
LIME SLURRY PROCESS
LOCATION IV[142]

Test Day [a]	SO_2 Emission Rate at Scrubber Inlet		SO_2 Emission Rate at Scrubber Outlet		Percent SO_2 Removal
	ng/J	lb/Million Btu	ng/J	lb/Million Btu	
1	2021	4.7	211	0.5	89.7
2	2175	5.1	230	0.5	89.4
3	2293	5.3	160	0.4	93.0
4	2277	5.3	179	0.4	92.2
5	2245	5.2	237	0.6	89.4
6	2344	5.5	194	0.5	91.6
7	2333	5.4	260	0.6	88.8
8	2310	5.4	186	0.4	92.0
9	2355	5.5	146	0.3	93.8
10	2318	5.4	189	0.4	91.8
11	2220	5.2	124	0.3	94.4
12	2334	5.4	94	0.2	96.0
13	2432	5.7	194	0.5	92.0
14	2418	5.6	127	0.3	94.7
15	2390	5.6	128	0.3	94.6
16	2255	5.2	205	0.5	91.0
17	2272	5.3	201	0.5	91.2
18	2318	5.4	218	0.5	90.6
19	2299	5.4	216	0.5	90.6
20	2262	5.3	199	0.5	91.3
21	2145	5.0	131	0.3	93.8
22	2273	5.3	185	0.4	91.9
23	2359	5.5	213	0.5	90.9
24	2116	4.9	150	0.4	93.4
25	2207	5.1	294	0.7	86.7
26	2245	5.2	279	0.6	87.6
27	2125	4.9	285	0.7	86.8
28	1990	4.6	149	0.3	92.4
29	1927	4.5	190	0.4	90.6
29 Day Average	2250	5.2	192	0.4	91.5

[a] 18 Hours/day minimum test time.

TABLE C.3-12. DAILY SUMMARY OF HOURLY BOILER LOADS LIME SLURRY PROCESS LOCATION IV[a,b]

Test Day[a]	Minimum Hourly Boiler Load (million Btu/hr)	24-Hour Average Boiler Load (million Btu/hr)	Maximum Hourly Boiler Load (million Btu/hr)
1	99	106	118
2	98	107	119
3	102	110	120
4	100	108	120
5	104	113	125
6	106	113	127
7	103	116	131
8	94	110	118
9	102	112	119
10	99	113	122
11	99	112	123
12	97	109	118
13	99	113	129
14	78	112	126
15	72	93	109
16	111	120	132
17	96	115	127
18	98	113	132
19	106	121	134
20	109	125	136
21	90	110	128
22	81	102	117
23	105	116	134
24	90	104	127
25	86	107	127
26	88	99	109
27	90	97	106
28	72	82	95
29	78	93	105

[a]18 Hours/day minimum test time.

[b]Reference 142.

TABLE C.3-13. DAILY SUMMARY OF pH LEVELS
LIME SLURRY PROCESS
LOCATION IV[a]

Test Day	Minimum pH Reading	Daily Average pH Level	Maximum pH Reading
1	7.8	7.9	8.0
2	7.9	8.3	8.5
3	4.6	6.3	8.0
4	7.6	7.7	7.8
5	5.8	6.6	7.6
6	8.0	8.2	8.4
7	7.2	7.4	7.6
8	7.5	7.9	8.2
9	7.1	7.4	8.0
10	7.0	7.3	7.8
11	7.4	7.5	7.6
12	8.0	8.5	9.2
13	7.4	7.5	7.6
14	7.2	7.3	7.4
15	7.6	8.4	9.9
16	6.2	6.5	7.0
17	6.8	6.8	6.9
18	7.8	8.3	8.8
19	6.6	7.4	8.3
20	7.8	7.9	8.0
21	7.8	7.9	8.0
22	7.8	7.9	7.9
23	8.0	8.1	8.2
24	7.8	7.9	8.0
25	5.6	6.3	6.8
26	4.8	5.3	6.0
27	3.8	4.3	4.7
28	6.3	6.6	7.0
29	4.7	5.6	6.1

[a]Reference 143.

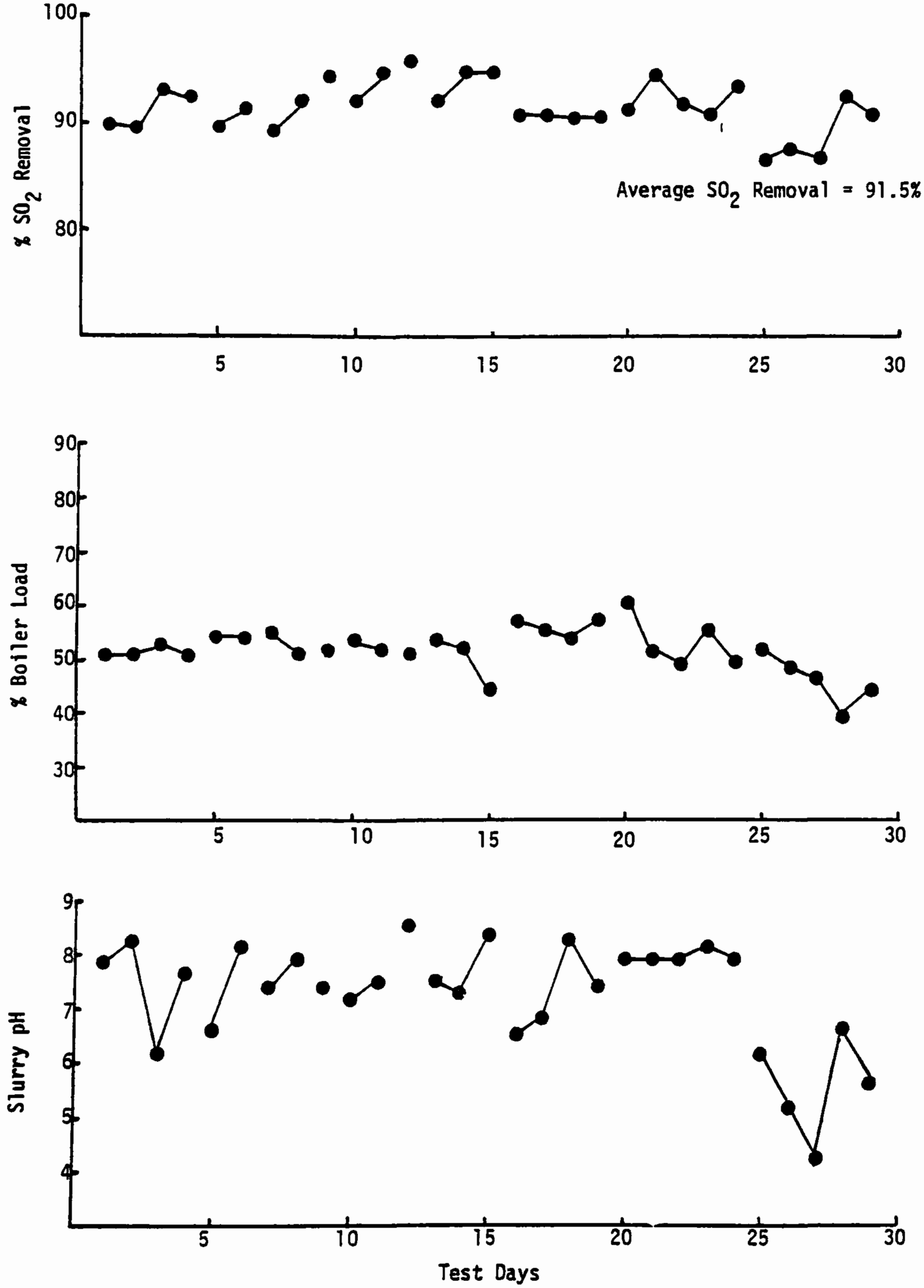

Figure C.3-4. Daily average SO_2 removal, boiler load, and slurry pH for lime slurry scrubbing process at Location IV.

Location IV - Limestone (with and without Adipic Acid Addition)

The FGD system at Location IV was also monitored during limestone operation. Tests were conducted both with and without adipic acid addition.

In 36 days of testing without adipic acid addition, SO_2 removal averaged 58.7 percent (Table C.3-14). This relatively low SO_2 removal is attributed to two factors: (1) the system is not designed for high SO_2 removal with limestone[144] and (2) evidence that the system was operated at gas flows of about 20 percent greater than the design value.[136] For these reasons, the results from limestone only tests are not considered representative of a well designed and operated industrial boiler wet FGD system.

As shown in Table C.3-15, SO_2 removal averaged 94.3 percent during 30 days of testing with adipic acid addition. This higher removal was attributed to the effects of adipic acid as well as the effort during the test program to maintain higher limestone feed rates than those used during limestone only testing.[144] Table C.3-16 presents daily average outlet SO_2, boiler load, adipic acid concentration, and slurry pH for the test period. Figure C.3-5 shows daily average SO_2 removal, boiler load, adipic acid concentration and slurry pH.

TABLE C.3-14. DAILY AVERAGE SO_2 REMOVAL RESULTS LIMESTONE SLURRY PROCESS LOCATION IV[145]

Test Day[a]	Emission Rate at Scrubber Inlet		Emission Rate at Scrubber Outlet		Percent SO_2 Removal
	ng/J	lb/Million Btu	ng/J	lb/Million Btu	
1	2351	5.5	1334	3.1	43.3
2	2705	6.3	1290	3.0	51.9
3	2792	6.5	912	2.1	66.8
4	2590	6.0	945	2.2	63.6
5	2670	6.2	1189	2.8	55.3
6	2652	6.2	1283	3.0	51.5
7	2681	6.2	1318	3.0	50.9
8	2705	6.3	1549	3.6	42.7
9	2691	6.3	1635	3.8	39.4
10	2762	6.4	1627	3.8	41.1
11	2983	6.9	1723	4.0	42.5
12	2922	6.8	1496	3.5	48.8
13	2740	6.4	1300	3.0	52.4
14	2551	5.9	1298	3.0	49.0
15	2764	6.4	1285	3.0	53.5
16	2744	6.4	1471	3.4	46.5
17	3043	7.1	1237	2.8	59.6
18	2897	6.7	1218	2.8	57.9
19	3038	7.1	1417	3.3	52.9
20	2435	5.7	1253	2.9	48.4
21	2340	5.4	1013	2.4	56.5
22	2484	5.8	928	2.2	62.5
23	2686	6.2	994	2.3	63.0
24	2672	6.2	1102	2.6	58.7
25	2662	6.2	989	2.3	62.8
26	2882	6.7	1101	2.6	61.1
27	3197	7.4	832	1.9	72.5
28	3646	8.5	806	1.9	76.4
29	3349	7.8	903	2.1	73.1
30	3386	7.9	1040	2.4	68.9
31	3296	7.7	946	2.2	71.2
32	3484	8.1	1002	2.3	71.4
33	3446	8.0	764	1.8	77.8
34	3227	7.5	758	1.8	76.5
35	3219	7.5	1012	2.4	68.3
36	2991	7.0	1256	2.9	57.9
36 Day Average	2880	6.7	1173	2.7	58.2

[a]18 Hours/day minimum test time.

TABLE C.3-15. DAILY AVERAGE SO_2 REMOVAL RESULTS FOR LIMESTONE SLURRY PROCESS WITH ADIPIC ACID ADDITION - LOCATION IV[144]

Test Day[a]	Emission Rate at Scrubber Inlet		Emission Rate at Scrubber Outlet		Percent SO_2 Removal
	ng/J	lb/Million Btu	ng/J	lb/Million Btu	
1	1720	4.0	129	0.3	92.5
2	1333	3.1	60	0.1	95.5
3	1767	4.1	103	0.2	94.2
4	1642	3.8	129	0.3	92.1
5	1789	4.2	159	0.4	91.1
6	1793	4.2	116	0.3	93.5
7	2098	4.9	116	0.3	94.5
8	1879	4.4	90	0.2	95.2
9	1913	4.5	95	0.2	95.1
10	2661	6.2	194	0.5	92.7
11	2240	5.2	129	0.3	94.2
12	2128	5.0	138	0.3	93.5
13	2244	5.2	65	0.2	97.1
14	1995	4.6	108	0.3	94.6
15	2356	5.5	237	0.6	90.0
16	2137	5.0	138	0.3	93.6
17	2644	6.2	138	0.3	94.8
18	2085	4.9	125	0.3	94.0
19	1943	4.5	165	0.4	90.5
20	2765	6.4	262	0.6	90.5
21	2313	5.4	155	0.4	93.3
22	2077	4.8	60	0.1	97.1
23	2180	5.1	56	0.1	97.4
24	2060	4.8	77	0.2	96.2
25	2266	5.3	142	0.3	93.7
26	2214	5.2	82	0.2	96.3
27	2322	5.4	73	0.2	96.9
28	2365	5.5	90	0.2	96.2
29	2648	6.2	146	0.3	94.5
30	2176	5.1	69	0.2	96.8
30 Day Average	2125	4.9	122	0.3	94.3

[a]18 Hours/day minimum test time.

TABLE C.3-16. DAILY AVERAGE BOILER LOAD, ADIPIC ACID CONCENTRATION AND SLURRY pH LOCATION IV[144]

Test Day[a]	Boiler Load %	Adipic Acid Conc. (ppm)	Slurry pH
1	49	2305	4.7
2	55	2920	4.9
3	64	2090	4.7
4	64	2290	4.9
5	67	2150	-
6	60	1770	5.0
7	59	2165	5.0
8	49	1890	5.0
9	46	1855	4.8
10	50	1870	4.9
11	49	2050	4.7
12	62	3000	-
13	55	2680	5.2
14	48	2420	5.4
15	48	2200	5.4
16	48	2240	4.7
17	46	2150	5.2
18	48	2130	5.3
19	46	-	5.0
20	38	-	-
21	34	1920	-
22	37	1950	4.9
23	30	2040	5.5
24	30	2160	4.8
25	36	2200	4.7
26	33	2170	4.6
27	33	2820	5.1
28	32	2850	5.1
29	31	2510	4.6
30	36	2400	4.7
30 day average	46	2257	5.0
Minimum	30	1770	4.6
Maximum	67	3000	5.5

[a] 18 Hours/day minimum test time.

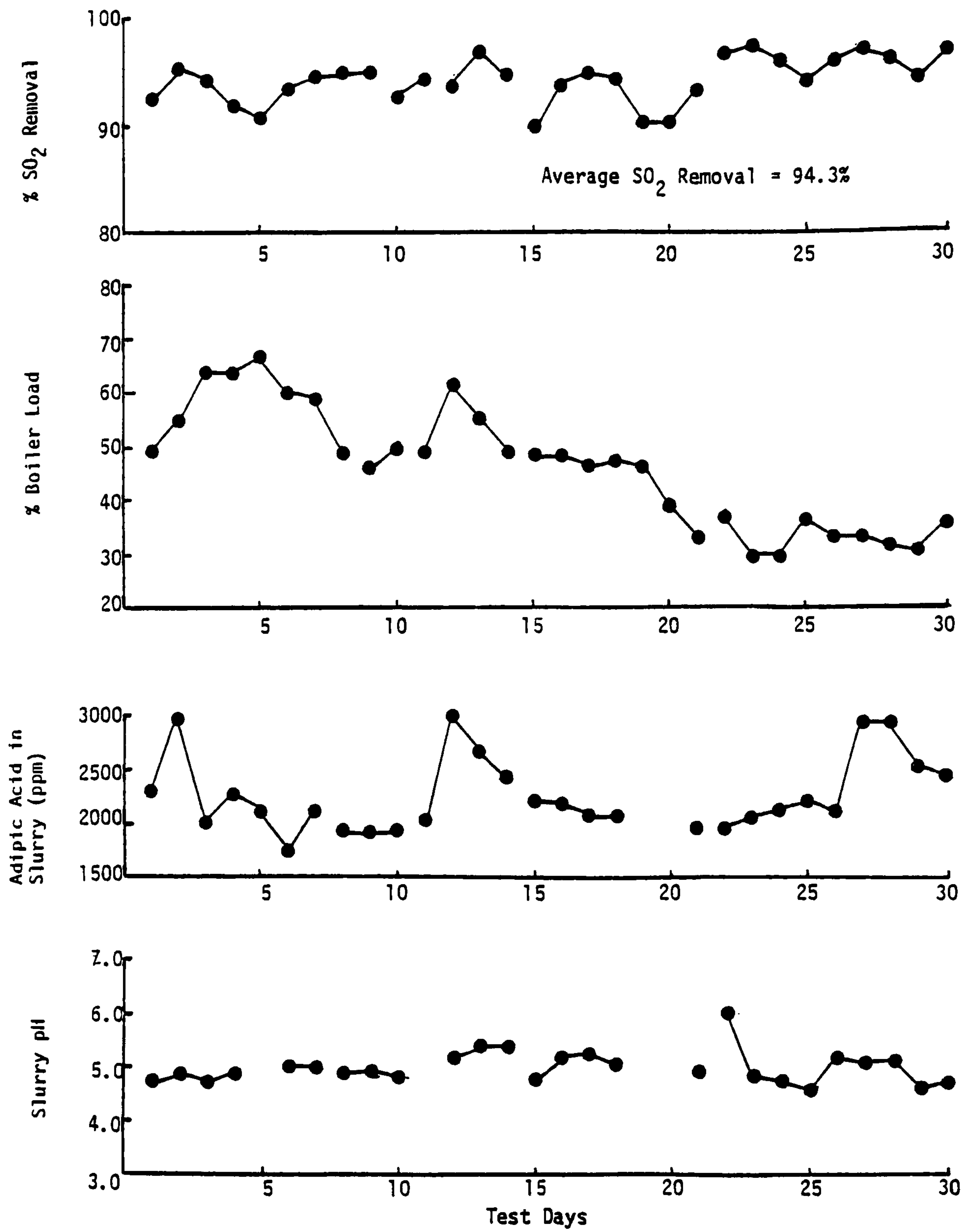

Figure C.3-5 Daily average SO_2 removal, boiler load, adipic acid concentration, and slurry pH for limestone system at Location IV.

Location V[146]

The FGD system monitored at plant location V is a turbulent contact absorber (TCA) prototype installation. The TCA unit, constructed by Universal Oil Products, uses a fluid bed of low density plastic spheres that migrate between retaining grids. The scrubbing medium is a lime slurry. The pilot plant scale wet scrubber handles a side stream of the flue gases from a coal-fired boiler power station having 10 turbines.

The daily averaged test results are presented in Table C.3-17. Continuous monitoring data was obtained for 42 test days.

Because this unit is designed and operated as pilot plant, it is not considered to be representative of industrial boiler wet FGD systems designed and operated for maximum SO_2 removal.[136]

TABLE C.3-17. DAILY AVERAGE SO_2 REMOVAL RESULTS
LIME SLURRY PROCESS
LOCATION V[147]

Test Day[a]	SO_2 Emission Rate at Scrubber Inlet		SO_2 Emission Rate at Scrubber Outlet		Percent SO_2 Removal
	ng/J	$\frac{\text{Lb}}{\text{Million Btu}}$	ng/J	$\frac{\text{Lb}}{\text{Million Btu}}$	
1	2541	5.9	264	0.6	89.6
2	2566	6.0	289	0.7	88.8
3	2549	5.9	306	0.7	88.0
4	2331	5.4	283	0.7	88.0
5	2270	5.3	237	0.6	89.7
6	2589	6.0	354	0.8	86.4
7	2588	6.0	380	0.9	85.5
8	2572	6.0	395	0.9	84.6
9	2449	5.7	347	0.8	85.8
10	2460	5.7	331	0.8	86.5
11	2266	5.3	247	0.6	89.1
12	2393	5.6	215	0.5	91.0
13	2274	5.3	240	0.6	89.5
14	2546	6.0	326	0.8	87.2
15	2711	6.3	314	0.7	88.4
16	2616	6.1	301	0.7	88.5
17	2322	5.4	227	0.5	90.5
18	2532	5.9	255	0.6	90.1
19	2250	5.2	194	0.5	91.4
20	2365	5.5	233	0.5	90.3
21	1961	4.6	160	0.4	92.1
22	2150	5.0	200	0.5	91.1
23	2440	5.7	253	0.6	89.7
24	2295	5.4	229	0.5	90.0
25	2313	5.4	331	0.8	85.9
26	1680	3.9	164	0.4	90.2
27	2163	5.0	270	0.6	88.0
28	2053	4.8	222	0.5	89.2
29	2132	5.0	351	0.8	83.7
30	2360	5.5	415	1.0	82.5
31	2635	6.1	367	0.9	86.1
32	2617	6.1	350	0.8	86.6
33	2594	6.0	309	0.7	88.1
34	2580	6.0	295	0.7	88.5
35	2579	6.0	319	0.7	87.6
36	2580	6.0	375	0.9	85.5
37	2315	5.4	258	0.6	88.9
38	2365	5.5	255	0.6	89.2
39	2486	5.8	280	0.7	88.8
40	2549	5.9	308	0.7	88.0
41	2225	5.2	210	0.5	90.9
42	2061		172	0.4	91.7
42 Day Average	2389	5.6	282	0.7	88.4

[a] 18 Hours/day minimum test time.

Location VI[148]

The FGD system monitored at plant location VI is a spray drying scrubber. The scrubbing sorbent is a 26 percent high quality lime (90-94% calcium oxide) slurry. Approximately 2 percent sulfur coal was burned during most of the test period. Efficiencies found when the daily inlet SO_2 concentrations are high (above 4.0 lb/10^6 Btu) average 75 percent.

The daily averaged test results are presented in Table C.3-18 for the 23 test days. During this period, boiler load averaged 114 million Btu/hr, with hourly loads ranging from 12 to 152 million Btu/hr.[149] Figure C.3-6 illustrates SO_2 removal and inlet SO_2 emissions for each test day at this site.

TABLE C.3-18. DAILY AVERAGE SO_2 REMOVAL RESULTS SPRAY DRYING PROCESS LOCATION VI[149]

Test Day[a]	SO_2 Emission Rate at Scrubber Inlet		SO_2 Emission Rate at Scrubber Outlet		Percent SO_2 Removal
	ng/J	Lb/Million Btu	ng/J	Lb/Million Btu	
1	1471	3.4	400	0.9	72.7
2	1316	3.1	390	0.9	70.3
3	1230	2.9	517	1.2	58.0
4	1613	3.8	634	1.5	60.7
5	1312	3.1	702	1.6	46.4
6	1436	3.3	568	1.3	60.4
7	1178	2.7	415	1.0	64.8
8	1118	2.6	452	1.1	59.5
9	1269	3.0	433	1.0	65.9
10	1372	3.2	638	1.5	53.5
11	1475	3.4	347	0.8	76.5
12	1449	3.4	393	0.9	72.8
13	1122	2.6	397	0.9	64.6
14	1578	3.7	460	1.1	70.9
15	1810	4.2	473	1.1	73.8
16	1557	3.6	627	1.5	59.8
17	1905	4.4	530	1.2	72.2
18	1888	4.4	418	1.0	77.9
19	1711	4.0	340	0.8	80.1
20	1608	3.7	340	0.8	78.9
21	1578	3.7	375	0.9	76.2
22	1578	3.7	339	0.8	78.5
23	1746	4.1	387	0.9	77.9
23 Day Average	1492	3.5	460	1.1	68.4

[a] 18 Hours/day minimum test time.

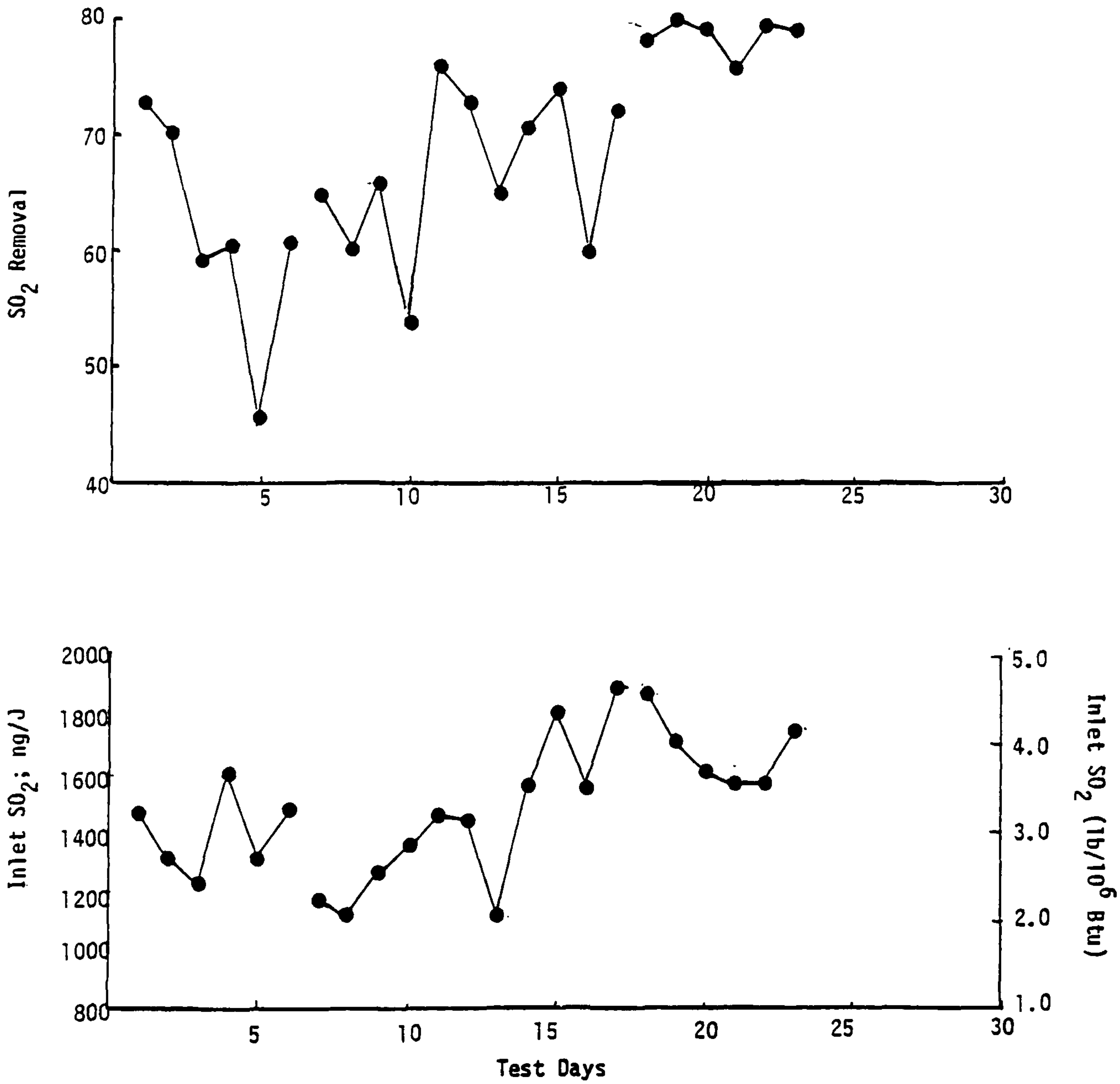

Figure C.3-6. Daily average SO_2 removal, inlet SO_2 for lime spray drying system at Location VI.

Location VII[150]

The location monitored is a 100,000 lb steam/hr coal/limestone feed fluidized-bed boiler (FBB).* The coal sulfur content of the bituminous coal burned during testing ranged from 1.5 - 2.5 weight percent. The boiler load during the period ranged from 50 to 60 percent.

The SO_2 control used at this location was coal/limestone injection. The design limestone flow rate was 3,133 lb/hr, with actual conditions ranging from 1,500 to 4,500 lb/hr. The Ca/S ratio varied from 2 10 compared to a design value of 3. Low fly ash reinjection rates may have increased SO_2 emissions by decreasing sorbent residence times.

*The plant was being operated in an extended shakedown phase so that operating conditions were not always in the intended design range.

TABLE C.3-19. DAILY AVERAGE SO_2 REMOVAL RESULTS FLUIDIZED-BED COMBUSTION PROCESS LOCATION VII[150]

Test Day[a]	SO_2 Emission Rate - Inlet		SO_2 Emission Rate - Inlet		Percent SO_2 Removal
	ng/J	lb/million Btu	ng/J	lb/million Btu	
1	1030	2.4	197	0.5	80.9
2	1030	2.4	256	0.6	75.1
3	1030	2.4	220	0.5	78.7
4	1090	2.5	171	0.4	84.3
5	1030	2.4	62	0.1	94.0
6	1030	2.4	55	0.1	94.7
7	1030	2.4	47	0.1	95.4
8	1030	2.4	88	0.2	91.4
9	1120	2.6	78	0.2	93.1
10	1236	2.9	49	0.1	96.2
11	1245	2.9	178	0.4	85.7
12	1439	3.3	242	0.6	83.2
13	1477	3.4	215	0.5	85.4
14	1679	3.9	224	0.5	86.3
14 Day Average	1178	2.7	149	0.3	87.5

[a]18 Hours/day minimum test time.

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APPENDIX D: EMISSION MEASUREMENT METHODS AND CONTINUOUS MONITORING

D.1 EMISSION MEASUREMENT METHODS

Since the characteristics of the emissions from nonfossil fuel fired boilers (NFFB) are similar to those from source categories for which new source performance standards (NSPS) have been promulgated (e.g., Subparts D and Da 40 CFR Part 60, Fossil-Fuel Fired Steam Generators and Electric Utility Steam Generators), it was not necessary to develop new or modified reference test methods for the data collection phase of this study. The emissions measured are criteria pollutants--particulate matter, oxides of nitrogen, and sulfur dioxide--and applicable manual reference test methods have been promulgated in Appendix A, 40 CFR Part 60. In addition, EPA has promulgated specifications and operating requirements for continuous monitoring of opacity in Appendix B, 40 CFR Part 60 and proposed revisions to the monitoring performance specifications in the Federal Register on October 10, 1979. The procedures used in the data collection study are described below by pollutant.

D.1.1 Particulates

EPA performed tests at nine facilities for particulate matter in accordance with EPA Reference Method 5 at elevated probe and filter temperatures as presently provided for in 40 CFR Part 60, Subparts D and Da. Two of the sources tested were controlled by electrostatic precipitators, three by wet scrubbers, one by controlled air combustion, two by fabric filters, and one by an electrostatic gravel bed filter.

Under the Fossil-Fuel Fired Steam Generator and Electric Utility Steam Generator Standards, the best systems of particulate control were not considered effective for sulfuric acid mist and EPA promulgated modifications of Method 5 to minimize the measurement of acid mist as particulate matter. These modifications allowed probe and filter sampling temperatures up to 160°C (320°F). Since the best systems of particulate control for NFFBs do not effectively collect sulfuric acid mist, similar provisions are recommended for this standard.

The remaining particulate emission data base was obtained from reports submitted by state agencies or industries operating nonfossil fuel fired boilers and were evaluated with respect to the testing methodology employed. Out of 144 particulate emission test reports reviewed, 68 were considered as properly conducted according to the EPA Methods. The other 76 either lacked sufficient information for a proper review, or were not considered to be tested according to EPA Methods.

The emission test reports were also reviewed to determine if the boiler and control equipment were operated properly during testing or if there were factors present in the system design or operation which would bias the test results. This review indicated that an additional six test reports could not be used due to abnormal conditions.

D.1.2 Sulfur Dioxide

Six of the NFFB sites tested by EPA for particulate emissions were also tested to determine the SO_2 emission rate. These tests were performed in accordance with EPA Reference Method 6.

D.1.3 Nitrogen Oxides

All nine of the NFFB sites tested by EPA for particulate were also tested to determine NO_x emission levels. These tests were performed in accordance with EPA Reference Method 7.

D.1.4 Visible Emissions

EPA conducted visible emission tests at nine facilities. At four facilities, visible emission tests were conducted simultaneously with EPA particulate sampling tests. In addition to the EPA tests, five of the particulate emission tests obtained from state and industry sources also contained visible emissions data which were used in this study. All visible emission data were obtained in accordance with EPA Reference Method 9.

D.2 COMPLIANCE TEST METHODS

The reference test methods and procedures available for determination of compliance with an emission limitation, along with the costs of each procedure, are discussed in this section. Standards for nitrogen oxides and sulfur dioxides which would require a reduction in the uncontrolled emissions of these pollutants are not being considered for nonfossil fuel fired boilers. Therefore, no compliance test methods are recommended for these pollutants. Boilers firing mixtures of fossil and nonfossil fuels may require SO_2 and NO_x reductions. The test methods applicable to these cases are EPA Reference Methods 6 and 7, as discussed in Appendix D of the Industrial Boiler Background Information Document.

D.2.1 Particulate Matter

The recommended performance test method for particulate matter for nonfossil fuel fired boilers is Method 5 modified to allow probe and filter temperatures up to 160°C (320°F). This is also the recommended test method for fossil fuel fired industrial steam generators. The particulate matter emissions from nonfossil fuel fired boilers are similar to those from fossil fuel fired industrial boilers. Also, nonfossil fuel fired boilers may fire significant amounts of fossil fuels under certain conditions. Therefore, it is recommended that the performance test method for particulate emissions for both industrial boilers and nonfossil fuel fired boilers be the same. In addition, the use of Method 17 is recommended as an alternative to Method 5 whenever the average stack gas temperature at the sampling location does not exceed 160°C (320°F).

Emission standards for nonfossil fuel fired boilers are expressed in terms of pollutant mass per unit of heat input. The F factor procedure is recommended for the determination of emission rates. The F factor is the ratio of the quantity of dry effluent gas (F_d) or of carbon dioxide (F_c) generated by combustion to the gross calorific value of the fuel and is constant for a given fuel. Used with a dilution correction value, the F factor can be used to correct pollutant concentration data to units of pollutant mass per unit of heat input. Method 19 (Appendix A, 40 CFR 60) includes the calculation procedures necessary for the emission rate determination using the F factors.

F factor values for the fuels fired in NFFBs can be determined from analyses of fuel samples and the calculation procedures in Method 19. However, obtaining representative samples of fuels is difficult and time-consuming and the analyses required are expensive. It is recommended that the published values for F factors be used where available. The F factors calculated for the representative fuels used in this study are shown in Section C.1 of Appendix C.

A combined fuel F factor can be calculated for the combined combustion of waste fuels and fossil fuels or for combinations of different waste fuels. These calculations procedures are included in Method 19. The calculations require a knowledge of the F factors for the fuels and the heat input rate attributable to each fuel. It is not critical that the fractions of heat input rate be precisely known for each fuel as the F factors for most waste materials and fossil fuels are similar.

Subpart A of 40 CFR 60 requires that facilities which are subject to standards of performance for new stationary sources must be constructed so that sampling ports adequate for the required performance tests are provided. Platforms, access, and utilities necessary to perform testing at those ports must also be provided.

Sampling costs for performing a test consisting of three Method 5 runs are estimated to be $10,000.[1] If in-plant personnel are used to conduct tests, the costs will be somewhat less.

D.2.2 Opacity

Method 9, "Visual Determination of the Opacity of Emissions from Stationary Sources," is recommended as the compliance test method for opacity. This method is applicable for the determination of opacity of effluent streams emitted from stacks.

Continuous monitors for opacity are not recommended for use in determining compliance with this regulation because an absolute accuracy check is not possible with the current state-of-the-art opacity monitoring systems.

D.3 MONITORING SYSTEMS

Though continuous opacity monitors are not recommended for use in determining compliance with this regulation, they can be used to monitor control system performance. The opacity monitoring systems that are adequate for other stationary sources, such as fossil fuel fired steam generators, covered by performance specifications contained in Appendix B of 40 CFR 60 Federal Register, October 6, 1975, should also be applicable to nonfossil fuel fired boilers except where condensed moisture is present in the exhaust stream. When wet scrubbers are used for emission reduction, monitoring of opacity is not applicable and another parameter such as pressure drop may be monitored as an indicator of emission control.

Equipment and installation costs for visible emissions monitoring are estimated to be $40,000 per site.[2] Annualized costs, which include an automated data reduction system, are estimated to be $10,800 per year per site.[3] Some economics in operating costs may be achieved if multiple systems are required at a given facility.

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2. Reference 1, p.4.

3. Reference 1.

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16. ABSTRACT

This document provides background information about air emissions and controlling these emissions for the nonfossil fuel fired boiler (NFFB) source category. This source category includes boilers firing wood, bagasse (sugar cane residue), municipal type solid waste, and refuse derived fuels. This document identifies the industries which use NFFBs and the numbers of new NFFBs expected to be built in 1982 through 1990. The uncontrolled emissions of particulate matter, sulfur dioxide, and nitrogen oxides are quantified and factors affecting these emissions are discussed. State and Federal regulations which apply to the NFFB source category are summarized. Control technologies to reduce these emissions are identified and emission test data are presented. Factors which affect the performance of emission control technologies are also discussed. Finally, environmental, energy and cost impacts of applying these control technologies to nonfossil fuel fired boilers are presented and discussed. This information was developed in support of a potential new source performance standard for nonfossil fuel fired boilers.

17. KEY WORDS AND DOCUMENT ANALYSIS

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